CANADIAN UTILITIES LIMITED

An ATCO Company

1998 ANNUAL REPORT

In 1998, ATCO Power, along with its joint venture partner, completed construction and commissioned the 180 MW Osborne cogeneration plant in South Australia.

Since May 1998, Canadian Utilities Limited has been undergoing significant reorganization. This reorganization is intended to put in place a structure that is more compatible with ongoing deregulation and restructuring of regulated activities. In conjunction with this reorganization, ATCO Group has embarked on a rebranding campaign whereby the companies will adopt the ATCO brand name. The new company names have been used in the narrative copy of the Review of Operations, but not in the Management's Discussion and Analysis nor in the Financial Statements.

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CANADIAN UTILITIES LIMITED

Corporate Profile

CU

ATCO Electric

ATCO Electric provides electric utility service to customers in more than 350 communities in Alberta, the Yukon and the Northwest Territories.

ATCO Power

ATCO Power is a developer, project manager, owner and operator of independent power projects in Canada, Great Britain and Australia.

ATCO Gas

ATCO Gas distributes natural gas to industrial, commercial and residential customers, primarily in urban areas in Alberta.

ATCO Pipelines

ATCO Pipelines transmits natural gas throughout Alberta using high pressure pipelines.

ATCO Midstream

ATCO Midstream's key areas of operation are natural gas gathering, processing, storage and retail gas management services.

ATCO Frontec

ATCO Frontec provides project management and technical services; operation and maintenance; technology transfer and training services to the defence, transportation and industrial sectors.

ATCO Singlepoint

ATCO Singlepoint was established as a subsidiary of Canadian Utilities to provide billing and call centre services to customers such as municipalities, utilities and other organizations.

ATCO Energy

ATCO Energy, a wholly owned subsidiary of Canadian Utilities, was incorporated on September 29, 1998 to participate in the deregulated gas and electricity markets in Alberta.

ATCO I-Tek

ATCO I-Tek was established in January 1999 as a division of Canadian Utilities to build, operate and support the information systems and technologies used within the ATCO Group of Companies.

Financial Highlights

CONSOLIDATED ANNUAL RESULTS

(Millions of Canadian dollars except share data)

Year Ended December 31

	1998	1997
Financial		
Revenues	**1,945.7**	1,927.6
Earnings attributable to Class A and Class B shares	**190.2**	181.5
Total assets	**4,437.2**	4,090.7
Class A and Class B shareholders' equity	**1,334.0**	1,245.4
Capital expenditures – net	**410.5**	353.8
Cash flow from operations	**426.8**	401.6
Class A Non-Voting and Class B Common Share Data		
Earnings per share	**3.00**	2.85
Dividends paid per share	**1.64**	1.56
Equity per share	**21.05**	19.66
Shares outstanding	**63,362,285**	63,339,685
Weighted average shares outstanding	**63,358,988**	63,714,222

CONSOLIDATED QUARTERLY RESULTS (1)

(Unaudited)

(Millions of Canadian dollars except per share data)

Three Months Ended

		March 31	June 30	September 30	December 31	Total
Revenues	**1998**	**557.6**	**407.3**	**375.5**	**605.3**	**1,945.7**
	1997	642.4	398.1	368.7	518.4	1,927.6
Earnings attributable to Class A and Class B shares	**1998**	**69.2**	**39.2**	**27.8**	**54.0**	**190.2**
	1997	65.3	37.7	26.8	51.7	181.5
Earnings per Class A and Class B share	**1998**	**1.09**	**0.62**	**0.44**	**0.85**	**3.00**
	1997	1.02	0.59	0.42	0.82	2.85

(1) *Because of seasonal fluctuations, particularly in the utility operations, quarterly earnings are not indicative of full year results.*

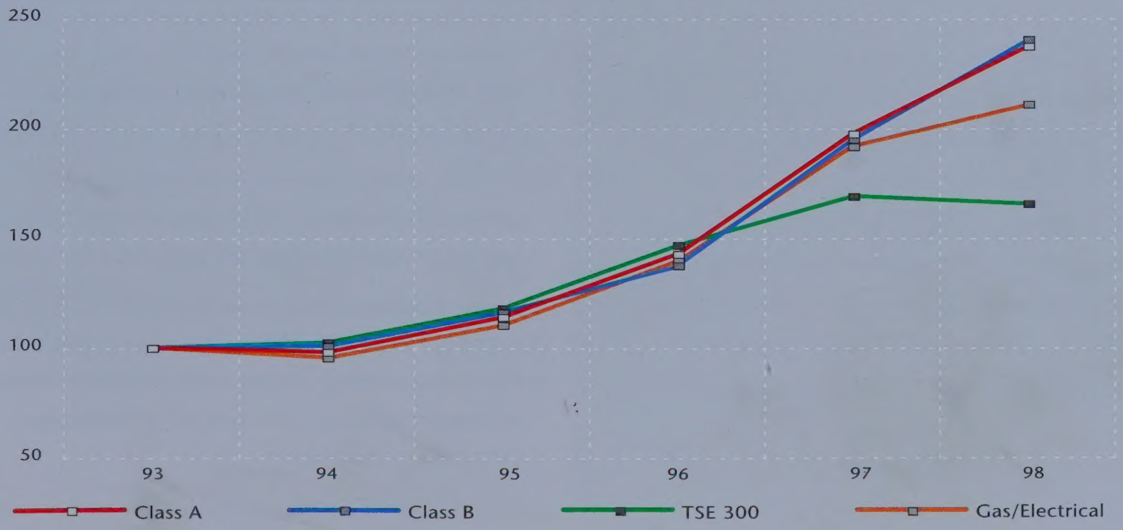
1998 Achievements

- ATCO Power commissioned the 180 megawatt ("MW") Osborne cogeneration plant in South Australia.
- ATCO Electric launched two new subsidiaries in 1998; Energen Inc., which builds, owns and operates small power projects and Ashcor Technologies Ltd., which markets flyash.
- Northwestern Utilities and Canadian Western Natural Gas announced the two companies would merge (subject to regulatory approvals) and be restructured into two new entities, ATCO Gas and ATCO Pipelines.
- ATCO Midstream purchased the Watelet Gas Plant which was a significant addition to the company's gas processing capability.
- ATCO Singlepoint was established to provide billing and call centre services to customers such as municipalities, utilities and other organizations.
- ATCO Energy was incorporated to participate in the deregulated gas and electricity markets in Alberta.

FIVE YEAR TOTAL RETURN ON $100 INVESTMENT

The graph below compares the cumulative shareholder return over the last five years on the Class A non-voting shares and Class B common shares of the Corporation (assuming a $100 investment was made on December 31, 1993) with the cumulative total return of the TSE 300 Composite Index and the TSE Gas/Electrical Subindex, assuming reinvestment of dividends.

	Cumulative Return	Compound Growth Rate
CU Class A	$239	19.0%
CU Class B	$241	19.2%
TSE 300	$166	10.7%
TSE Gas/Electrical	$211	16.1%



Letter to the Share Owners

Office of the Chairman;
From the left, standing:
William L. Britton, Lead Director;
Basil K. French, Lead Director;
Nancy C. Southern, Deputy Chairman & Deputy Chief Executive Officer;
seated: Susan R. Werth, Vice President, Administration;
Craighton O. Twa, President & Chief Operating Officer;
James A. Campbell, Senior Vice President Finance & Chief Financial Officer and
Ronald D. Southern, Chairman and Chief Executive Officer.

Canadian Utilities achieved record earnings in 1998. Our people, utilizing great transparency yet enjoying relative independence and self sufficiency at all levels, produced impressive momentum, and by any measure, were the leading force in the strong performance turned in by each of our operating companies.

1998 earnings were $3.00 per share - $190.2 million compared to $2.85 per share - $181.5 million recorded in 1997.

Cash flow from operations increased to $426.8 million compared to $401.6 million last year.

Capital expenditures rose to $410 million. This is $100 million per annum greater than the capital expenditures of five years ago. The expenditures were driven by investments in power generation, midstream gas processing, and information technology.

Total share owner returns over the last five years are shown graphically on page 3.

ACHIEVEMENT HIGHLIGHTS

During 1998, significant efforts were undertaken to identify and position our businesses to seize opportunities emerging in the deregulated gas and electric markets in Canada and Australia. The first phase of our preparations has centred around a restructuring and rebranding plan for our operating units.

Part of our restructuring plan, subject to regulatory approval, is the merger of our two gas transmission and distribution companies. The resulting single entity will provide improved efficiency to our customers.

Also subject to regulatory approval is a proposal for the reorganization of Canadian Utilities. A new subsidiary of Canadian Utilities, to be known as CU Inc., will acquire all of the common shares and debt of the regulated subsidiaries and assume the obligations of Canadian Utilities under its trust indenture.

The reorganization, which also requires Canadian Utilities share owner approval, will separate the regulated utility businesses from its non-regulated businesses and provide the financing flexibility needed to fund and execute new greenfield endeavours. Concurrent with the reorganization, Canadian Utilities is seeking approval from its debenture holders for amendments to its trust indenture.

A new company named ATCO Singlepoint was successfully launched during 1998 and is now providing the City of Red Deer with call centre and billing services for all municipal utility services including electricity, gas, water, sewer and garbage collection.

Another new company named ATCO Energy was established to provide retail natural gas and electric sales in the evolving deregulated marketplace.

Adoption of the ATCO brand name will apply to all principal operating subsidiaries. A preview of our rebranding program is contained at the beginning of this report. Our public company name, Canadian Utilities Limited, will remain unchanged.

We are pleased to report that several other objectives in areas of operations, finance and governance were successfully completed in 1998.

Most importantly, the granite-like cornerstone for our strategy considerations and operational goals, known as our separate and distinct financial plan, was revisited and updated to the year 2005.

The area of risk management was reviewed, domiciling responsibility to each of our business unit presidents with central oversight capability.

We completed streamlining audit and governance functions for all our operating subsidiaries and created a database within our information technology protocols to allow management and directors to share information and reduce paper flows.

An extensive cost and efficiency analysis concluded against out sourcing our data processing and information technology operations. We are very pleased with the progress made in this centralized function, branded ATCO I-Tek, to align our technology and business strategies, to focus on effective and efficient service delivery, and to provide domiciled strong governance.

We have had a steady focus on our year 2000 programs. As we near completion of the remediation of our systems, we are increasing the emphasis on contingency planning for potential impacts from third parties, and each unit in the group is committed to minimizing the impact of the year 2000 on our operations.

Our staffing levels have been refined as have our business processes, to assure premium performance in each unit... now... and in the future.

ELECTRIC POWER

Utility Operations

An ATCO Electric crew installs a fibreglass crossarm north of Halkirk, Alberta.

ATCO ELECTRIC

Canadian Utilities provides electric utility service through four operating companies, Alberta Power Limited and its subsidiaries, The Yukon Electrical Company Limited, Northland Utilities (NWT) Limited and Northland Utilities (Yellowknife) Limited.

Under our new restructuring plan, Alberta Power will be renamed ATCO Electric. The company and its subsidiaries will continue to supply electric utility service to customers in more than 350 communities in Alberta, the Yukon, Northwest Territories, Saskatchewan and British Columbia.

In 1998, combined electric sales increased to 10,188 million kilowatt ("KW") hours with 87% to industrial and commercial customers, 9% to residential and 4% to farm. More than 450 industrial customers were added in Alberta in 1998, mainly in the oil field sector.

Sales for ATCO Electric have increased by 26% since 1993. During that same period, on a sales per employee basis, our efficiencies have improved by more than 45%.

Capital spending for ATCO Electric totaled $118 million in 1998, including $63 million on distribution projects, $25 million on transmission projects and $24 million for generation.

ATCO Electric continues to be an active participant in discussions related to deregulation. Economic growth and the move towards a competitive market for generation have resulted in a transition period where electricity supply is tight for Alberta as a whole. In 1998, the company worked with others in the industry to manage this issue and minimize power curtailments to customers.

In 1998, the company launched two new subsidiaries; ENERGEN Inc. to build, own and operate small power projects of less than 25 MW and ASHCOR Technologies Ltd. to market flyash, a by-product of coal-fired generating plants. ASHCOR provides ATCO Electric with a new revenue source, while reducing flyash disposal costs.

Rate and tariff issues continue to be an important focus for ATCO Electric. In May, the company received an Alberta Energy and Utilities Board ("AEUB") decision approving a negotiated settlement that determined its revenue requirement for 1998.

In July, the company filed a Phase 2 rate application with the AEUB. This Phase 2 application will determine how ATCO Electric's approved revenue requirement for 1998 is recovered from different customer classes. The application includes a proposed direct access tariff that is the first step in the move towards customer choice. It allows large customers to choose whether to buy energy from their local distributor, or directly from the province's power pool.

A 1999/2000 General Tariff Application was also filed in 1998 and a hearing is expected to be held in the second quarter of 1999.

In 1998, the company contracted with ATCO Singlepoint to provide centralized call centre services to ATCO Electric customers with the convenience of a single telephone number for all inquiries, along with extended hours of operation.

In 1999, ATCO Electric will enter a transition phase to prepare for a more deregulated environment, with a focus on the power transmission and distribution business. In 1998, the Alberta legislature amended the Electric Utilities Act to specify a process for deregulating existing utility owned generating plants by January 1, 2001. The Act requires that vertically integrated electric utilities ensure that generation operations are separate and distinct from distribution and transmission functions.

ELECTRIC POWER

Independent Power Production

On February 19, 1999, ATCO Group President & Chief Operating Officer, C.O. Twa (right) and ATCO Power President, G.K. Bauer, (left) participated in the official grand opening of the 180 MW Osborne cogeneration plant near Adelaide, South Australia.

ATCO POWER

Since its inception as a greenfields company just ten years ago, CU Power International Limited ("CUPIL") has established a solid reputation as a developer, project manager, owner and operator of independent power projects. Under its new identity, ATCO Power, that reputation will be maintained and enhanced. It currently operates 1,450 MW of non-regulated generating capacity. In addition, it has almost 500 MW of projects under construction and almost 1,000 MW of projects in development.

Canada

In 1998, ATCO Power completed construction of a jointly owned 85 MW gas-fired cogeneration project at Amoco's Primrose Heavy Oil operation in northeast Alberta, the first independent power project completed since Alberta's deregulation of the electrical industry.

In April 1998, the company was selected by the Grid Company of Alberta and the new Transmission Administrator to build, own and operate a 43 MW gas-fired generating station at Poplar Hill, Alberta.

During the year, ATCO Power announced it had formed a joint venture with Nova and Epcor to build, own and operate a 416 MW gas-fired cogeneration plant on Nova's petrochemical site at Joffre, Alberta. The plant is under construction and is scheduled to come on stream early in the year 2000.

In December 1998, a joint venture between ATCO Power, Ontario Hydro, Hydro Mississauga and Toronto Hydro was announced to pursue the development of a 550 MW gas-fired combined-cycle power plant at the Lakeview Generating Station site in Mississauga, Ontario.

Also in 1998, the company was selected by Shell Canada Limited as the owner and operator of a 172 MW gas-fired cogeneration plant to provide power and hot water to Shell's proposed Muskeg River mine in northeastern Alberta.

Australia

Construction of the 180 MW cogeneration plant in Osborne, South Australia was completed and the plant was commissioned in December 1998.

ATCO Power and Boral Energy also announced the company would proceed with a Development Application for a second stage power station project adjacent to the Osborne plant site.

During 1998, ATCO Power concluded commercial negotiations on its second joint venture power plant in Australia, a 33 MW electrical and 55 MW thermal equivalent cogeneration/ combined cycle power plant, part of British Petroleum's Queensland Clean Fuels Project.

United Kingdom

The Barking Power Station continues to be the flagship of ATCO Power's operations. The jointly owned and operated 1,000 MW gas fired combined cycle power station, located east of London, England delivered another year of successful operations and for the second consecutive year surpassed its availability targets.

The Heathrow Cogeneration Plant also met its availability targets during 1998. The plant, which has a 14 MW gas-fired turbine and a 40 MW boiler, supplies electricity and hot water to British Airports Authority plc.

Ireland

ATCO Power continues to pursue opportunities with its Irish joint venture partner for gas fired generating stations in Ireland, as that country liberalizes its electricity market to comply with directives from the European Union.

ELECTRIC POWER

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ELECTRIC POWER

System Map

Northland Utilities (NWT) Limited
Northland Utilities (Yellowknife) Limited

The Yukon Electrical
Company Limited

Generating Plants
Major Transmission
Lines Owned By Others
Service Area
Other Electric Utilities
Unallocated

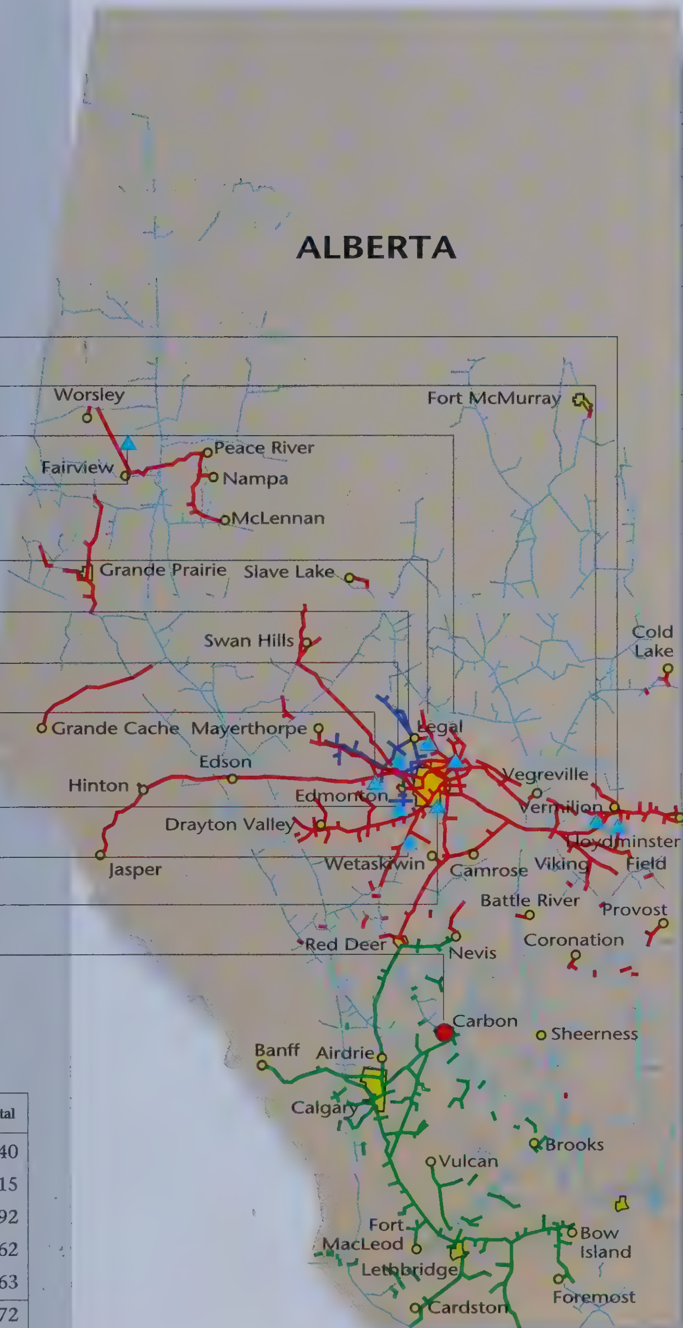
Retail Electric Sales
(Alberta, Yukon and Northwest Territories)

	Millions of Kilowatt Hours	% of Total
Industrial	7,294	71.6
Commercial	1,541	15.1
Residential	880	8.6
Company Rural	240	2.4
Rural Electrification Associations	203	2.0
Other	30	0.3
Total	10,188	100.0

NATURAL GAS

System Map

- ATCO Midstream Facilities
- Northwestern Utilities
- Canadian Western Natural Gas
- ATCO Midstream
- Other Major Gas Pipelines



ATCO MIDSTREAM FACILITIES

Scovil Lake Gas Plant

Kinsella Gas Gathering

Fort Saskatchewan Ethane Extraction Plant

Montag Gas Plant

Carbondale Gas Plant

Integrated Gas System

Villeneuve Ethane Extraction Plant

Riviere Gas Plant

Golden Spike Gas Plant

Watelet Gas Plant

Edmonton Ethane Extraction Plant

Carbon Storage

ATCO GAS/ATCO PIPELINES

Natural Gas Sales and Transportation (Terajoules)

	Sales	Transportation	Total
Industrial	11,497	316,443	327,940
Commercial	91,387	1,428	92,815
Residential	99,892	0	99,892
Other	8,639	292,523	301,162
Affiliates	59	32,504	32,563
Total System Throughput	211,474	642,898	854,372

NATURAL GAS
Utility Operations

An ATCO Gas employee installing a meter in a multiple meter residential system.

Northwestern Utilities Limited and Canadian Western Natural Gas Company Limited announced in June 1998 that the two companies would be merged and restructured into two new entities. ATCO Gas distributes natural gas to institutional, commercial and residential customers, primarily in urban areas in Alberta. ATCO Pipelines, transmits natural gas throughout Alberta using high pressure pipelines. This reorganization is subject to AEUB approval and hearings began in February 1999.

ATCO GAS

ATCO Gas is the Group's newly formed provincial gas distribution company which provides safe, efficient and economical service for the delivery of natural gas to Albertans. About 290 communities in Alberta receive gas service from ATCO Gas, comprising over 80% of natural gas customers in the province.

Growth and Productivity

Most of the ATCO Gas service territory experienced strong customer growth in 1998, particularly in Calgary, metro Edmonton, Grande Prairie and Red Deer. Approximately 23,000 new sales customers were added, bringing the total customers served by ATCO Gas to approximately 780,000. Most of this growth resulted from the favourable Alberta business and economic climate. Approximately 1,200 customers were added with the purchase of the CFB Cold Lake distribution system in early 1998.

Although record throughput on the Northwestern and Canadian Western systems exceeded 850 petajoules ("PJ"), actual sales volumes were reduced from 212 PJs in 1997 to 211 PJs in 1998 as a result of warmer than normal temperatures throughout the Province.

Operating and maintenance costs were lower in 1998 than 1997 as a result of restructuring efficiencies and a continuing emphasis on cost reduction.

Rates and Regulatory Issues

Rates charged to customers in Northwestern's service area in 1998 were at the level set out in the five-year agreement with customers and approved by the AEUB covering the five years 1998 through 2002. As a result, service rates for Northwestern's customers remained constant with those charged in the prior three years. The positive impact of restructuring allowed ATCO Gas to reopen the five-year negotiated settlement for the purpose of implementing a 1.426% decrease in service rates effective January 1, 1999.

In Canadian Western's service area, service rates have not increased since 1994, however, Canadian Western made an interim refund to customers of $10 million in November 1998 to reflect a possible reduction in rates for 1997 and 1998. Final rate levels for 1998 will be approved by the AEUB when it issues its decision after consideration of the hearings that occurred in January through March, 1999.

NATURAL GAS

Transmission

Banff Pipeline Looping Project, Summer 1998.

ATCO PIPELINES

ATCO Pipelines, comprised of the transmission assets of Canadian Western Natural Gas Company Limited and Northwestern Utilities Limited, will focus on growing its transportation services to producers, industrials and the core market.

ATCO Pipelines began transporting natural gas in 1912 with the completion of the pipeline to bring gas from the Bow Island field to Calgary, Lethbridge and other communities along the way. Today, ATCO Pipelines has more than 9,000 kilometres ("km") of pipeline with 170 receipt points connecting 245 producers with the Alberta core market and 80 industrial customers.

In the last 18 months, significant changes to meet producer and industrial customers' business requirements have been implemented. Account based receipt and delivery services provide increased customer flexibility throughout the province, with terms and conditions based on negotiated settlements reached with industrial and producer customers. In addition to physical transportation service, ATCO Pipelines offers a number of market services, such as exchange and transfers of gas on system. Customers can access their account information anytime, day or night, via the Internet, using TIS Online.

Transportation Growth

'Debottlenecking' facilities, installed in 1997, enabled significant growth in northern producer receipts during 1998. A 27 km loop of the Pembina pipeline was also required to transport the increased volumes.

The Carseland extension, completed in 1997, facilitated 1998 growth in southern producer receipts. To increase the company's ability to move this gas during the warm summer months, a 900 kilowatt ("KW") compressor was installed at Beiseker.

To meet increased end use demand in the Canmore and Banff areas, Phase IV of the Banff Transmission Line Looping project was completed in 1998 with the installation of 25 km of 323 millimetre pipe between Seebe and Canmore. As a result of extensive negotiations with Alberta Transportation and Utilities, approval was received to install the pipeline primarily within the TransCanada Highway right-of-way, which reduced costs and minimized the impact to the environment. In addition, a 20 km loop of the Jasper Transmission Pipeline was completed to meet increased load requirements in the Jasper area. Despite difficult, rocky terrain encountered on both projects, construction was completed on time to ensure security of supply for the 1998/99 winter.

ATCO Pipelines delivers the Alberta energy advantage by providing flexible, responsive and dependable transportation service within the province. Throughput on the system increased 15% in 1998.

NATURAL GAS

Gathering, Processing & Services

In July of 1998, ATCO Midstream acquired the Watelet Gas Plant and an extensive gathering system from Northstar Energy Corporation.

ATCO MIDSTREAM

The mission of ATCO Midstream (formerly ATCO Gas Services) is to profitably expand operations in key areas of gas gathering and processing; and to provide gas storage and retail gas management services.

ATCO Midstream experienced a profitable 1998 due to a number of factors. The company's diverse asset base was key to successes in both the gathering and processing business and in the storage business. Throughout 1998, low natural gas liquids ("NGL") prices affected earnings, despite all ATCO Midstream processing facilities operating at or near full capacity. However, the company strived to minimize its exposure to the low commodity prices. Low natural gas prices during the summer coupled with high natural gas prices in the winter resulted in strong returns from the storage and hub services area.

The gas gathering and processing business unit worked to optimize and maximize gas flows through existing assets. Natural gas receipts into the Integrated Gas System ("IGS") increased by more than 40% to exceed 100 million cubic feet per day ("mmcfd"). Negotiation of 18 new receipt arrangements occurred, and the debottlenecking of the system. The IGS is now operating near capacity and ATCO Midstream is actively looking at ways to continue expanding this system of pipelines and plants. The effect of low NGL prices resulted in lower than expected earnings at the Edmonton, Fort Saskatchewan and Villeneuve ethane extraction plants.

In July of 1998, ATCO Midstream acquired the Watelet gas plant and an extensive gathering system from Northstar Energy Corporation. This sour gas plant, with licenced capacity of 17 mmcfd, is strategically located to provide custom gas processing services to producers in the Watelet, Wizard Lake, Thorsby and Leduc Woodbend fields of central Alberta. This significant addition to ATCO Midstream's portfolio of processing plants is currently operating at capacity, with a plant expansion review currently underway.

The company also completed a year of detailed work on a proposed expansion of the Golden Spike sour gas processing plant that will see capacity increased from 15 mmcfd to 40 mmcfd. Approvals were received from the AEUB and other regulatory agencies in late 1998 and plant construction commenced in January of 1999. The expanded plant is scheduled to begin additional processing in the fall of 1999.

The storage and hub services unit increased ATCO Midstream's storage business through a number of innovative transactions in a very dynamic storage environment. The Alberta storage market experienced a significant upturn in 1998 due to export pipeline expansions that increased the amount of gas that could access markets outside Alberta.

ATCO Midstream was able to execute a unique storage arrangement with Imperial Oil Resources at their Golden Spike reservoir during the 1998/99 storage year. This transaction has led to an exclusive arrangement between ATCO Midstream and Imperial Oil Resources for the development of Golden Spike as a long term commercial storage facility.

ATCO Midstream's experienced staff and strategic asset base will position the company to address challenges and capture significant opportunities in 1999.

Technical Services & Facilities Management

An ATCO Frontec employee at Canyon Mountain, in the Yukon, one of 160 NorthwesTel sites for which the company provides diesel power generation, maintenance and fuel re-supply services.

ATCO FRONTEC

Established in 1986, this greenfield company has become a leader in technical services and facilities management. In 1998, Frontec continued to capitalize on its ability to establish effective alliances that provide comprehensive service packages to customers in both the public and private sectors across North America. The company will be renamed ATCO Frontec under the rebranding program.

Facilities Operation and Airports

One of the major initiatives for the year culminated in Bombardier Services Inc. awarding ATCO Frontec a two year contract to provide groundside support services at CFB Moose Jaw. The multi-million dollar contract covers the transition to the 20 year NATO Flying Training in Canada program, which is planned to start during 2001.

ATCO Frontec expanded its base of airport business with several new and renewed airport contracts. These included the North Bay Airport and the Castlegar, Dawson Creek and Penticton Airports in British Columbia.

Frontec Services Limited – Northern Operations

In 1998, the company established a joint venture with the Dogrib Rae Band to pursue logistics work, primarily in the resource sector. Its jointly held company, Tli Cho Logistics, officially incorporated in early 1999, won separate contracts to supply and manage fuel distribution services for Diavik Diamond Mines Inc., and to manage fuel deliveries for BHP Diamonds Inc. Uqsuq Corporation, an alliance with Nunasi Corporation and Qikiqtaaluk Corporation, won the contract for fuel storage and distribution in Resolute Bay, NWT. This new contract involves the biannual storage of 20 million litres of fuel and the sale and distribution of up to 10 million litres annually. Through a joint venture with Northern Aboriginal Services Co., ATCO Frontec also successfully completed the first year of a contract to operate and maintain 160 power-generating systems for NorthwesTel.

Radar and Communication Systems

As part of the Region/Sector Air Operations Center Modernization Project, ATCO Frontec worked with leading computer, communications and defence companies in Canada and the United States to modernize computer systems that are essential to North America's air defence. The company's initial work on the modernization of five radar-processing sites has already been commended by senior government personnel and by project partners, and work has been expanded to include a sixth site, Griffiss Air Force Base near Rome, New York.

Property Management

Through its property management division, ATCO Frontec began an innovative facilities management project in January 1998. The operating environment requires Frontec project staff to be integrated with Nortel Networks' Enterprise Solutions business unit in Calgary. Working within Nortel Networks' offices, ATCO Frontec maintains building functions and services, including the cafeteria, security, shuttle bus, electrical and HVAC systems, space planning and building layout.

ATCO Travel

A long-time provider of travel services within the entire ATCO Group, ATCO Travel has expanded its corporate base by securing 15 new major accounts. As well, ATCO Travel has successfully moved from a commission to a fee-based operation and has established an interactive web site, www.atcotravel.com.

Torngait Services

Torngait Services, a limited partnership with the Labrador Inuit, continues to provide camp management services and logistics support to exploration camps at Voisey's Bay and Anaktalak Bay, Labrador.

New Ventures

ATCO Singlepoint delivers one-stop billing and call centre services to the Alberta market-place, including the City of Red Deer.

ATCO SINGLEPOINT

ATCO Singlepoint was established as a subsidiary of Canadian Utilities to provide billing and call centre services to customers such as municipalities, utilities and other organizations.

Clients include the City of Red Deer, which contracts with ATCO Singlepoint for a full range of billing and call centre functions to support city services related to electricity, water, sewer and garbage.

This new company also provides billing, credit and collections, customer account services and call centre support to operating companies in the ATCO Group.

ATCO ENERGY

ATCO Energy, a wholly owned subsidiary of Canadian Utilities, was incorporated on September 29, 1998 to participate in the deregulated gas and electricity markets in Alberta. These markets are currently being restructured to provide competition and customer choice in retail energy supply.

ATCO Energy currently provides natural gas supply management services to operating companies in the ATCO Group.

ATCO I-TEK

As a result of a review and analysis of the ATCO Group's technology service needs, ATCO I-Tek (Information Technology Enabling Knowledge) was established in January 1999 to operate and support the information systems and technologies used within the ATCO Group of Companies. ATCO I-Tek's mandate is to bring cost reduction benefits to these contracts by expanding their services to other clients with similar requirements.

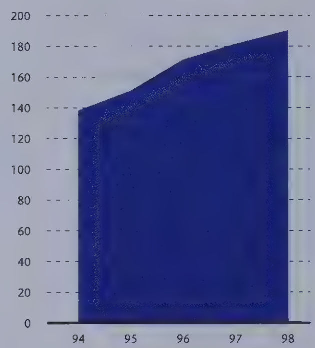
ATCO I-Tek, a division of Canadian Utilities, consists of 255 information technology professional staff, complemented by another 90 contract staff, who operate and support a secured enterprise computing environment. This environment consists of over 3,000 desktop and laptop computers, more than 200 applications, and network connections to over 126 sites throughout western Canada, the Yukon and the Northwest Territories.

ATCO I-Tek has formal, long-term service agreements in place with operating companies in the ATCO Group.

Management's Discussion and Analysis of Financial Condition and Results of Operations

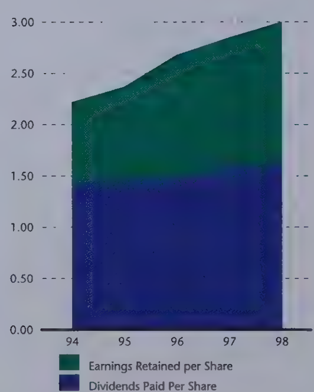
EARNINGS ATTRIBUTABLE TO CLASS A AND CLASS B SHARES

(millions of dollars)



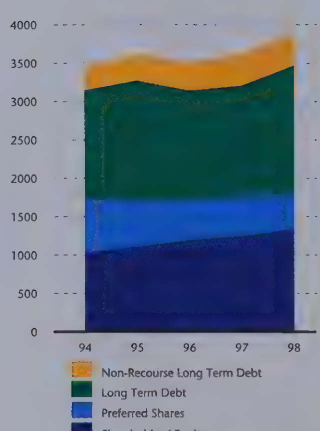
EARNING PER CLASS A AND CLASS B SHARES

(dollars)



CAPITALIZATION

(millions of dollars)



The following discussion and analysis of financial condition and results of operations of the Corporation for the years ended December 31, 1998 and 1997 should be read in conjunction with the Corporation's audited consolidated financial statements and related notes contained in this annual report.

The Corporation's annual audited financial statements are consolidated from five business segments: regulated natural gas operations, regulated electric operations, power generation, other businesses and corporate (refer to Note 13 to the consolidated financial statements). Transactions between segments are eliminated in all reporting of the Corporation's consolidated financial information.

RESULTS OF OPERATIONS

Consolidated Operations

Segmented revenues and earnings attributable to Class A and Class B shares for the years 1997 and 1998 were as follows:

	Revenues		Earnings	
(Millions of Canadian Dollars)	**1998**	1997	**1998**	1997
Regulated Natural Gas Operations	**873.5**	910.8	**68.7**	67.3
Regulated Electric Operations	**672.2**	662.7	**86.5**	84.2
Power Generation	**193.0**	174.8	**26.1**	20.9
Other Businesses	**206.3**	178.8	**14.2**	12.2
Corporate	**0.7**	0.5	**(4.7)**	(3.1)
Intersegment Eliminations	**–**	–	**(0.6)**	–
Consolidated	**1,945.7**	1,927.6	**190.2**	181.5

Note:
Certain 1997 comparative figures have been reclassified to conform with the current year's presentation.

Earnings per share increased in 1998 to $3.00 from $2.85 in 1997. Return on common equity was 14.8%, unchanged from 1997. All operating segments of the Corporation contributed to the improved earnings performance in 1998.

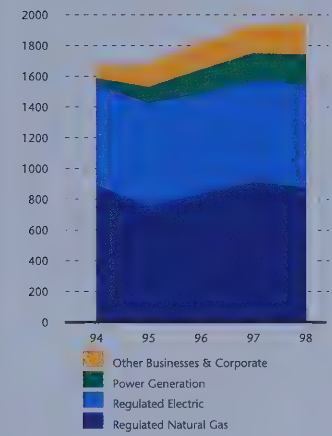
Depreciation and depletion expenses rose $7.9 million to $204.1 million in 1998, primarily as a result of capital additions during 1997 and 1998.

Interest expense for 1998 increased by $5.7 million to $173.0 million. This increase was primarily due to new financing in regulated natural gas operations, partially offset by the refinancing of maturing debt at lower rates. $7.9 million of interest was capitalized for projects under construction in power generation operations.

Dividends on retractable preferred shares for 1998 decreased by $0.6 million to $18.0 million primarily as a result of the redemption of $68.1 million of retractable preferred shares on December 1, 1998. Dividends on non-retractable equity preferred shares for 1998 decreased by $2.0 million to $10.4 million primarily as a result of the redemption and refinancing of $109.5 million of non-retractable equity preferred shares at lower dividend rates in October 1997, partially offset by a reclassification of $56.9 million of retractable preferred shares to non-retractable equity preferred shares on December 1, 1998.

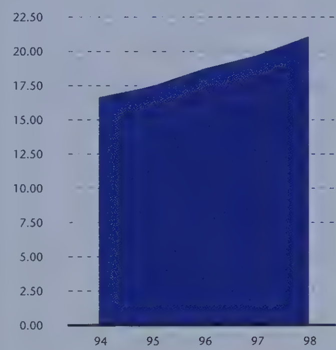
Interest and other income for 1998 increased by $2.3 million to $17.6 million primarily as a result of higher earnings from increased cash balances on deposit.

Income taxes for 1998 increased by $12.4 million to $180.5 million. The increase was primarily due to higher earnings before income taxes.



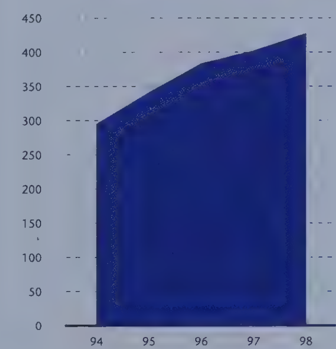
REVENUES

(millions of dollars)



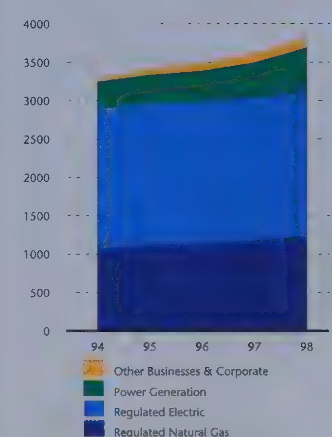
EQUITY PER SHARE

(dollars)



CASH FLOW FROM OPERATIONS

(millions of dollars)



PROPERTY, PLANT AND EQUIPMENT

(millions of dollars)

Regulated Natural Gas Operations

Earnings from regulated natural gas operations for 1998, which amounted to 36.1% of consolidated earnings of the Corporation, increased by $1.4 million to $68.7 million. Temperatures in 1998 were 3.2% warmer than normal, whereas temperatures in 1997 were 1.0% warmer than normal.

Revenues in 1998 decreased by $37.3 million to $873.8 million. The primary reason for the decrease was lower natural gas supply costs recovered in customer rates, lower sales per customer and the impact of warmer temperatures which were 1.3% warmer than in 1997, partially offset by customer growth.

Operating expenses for 1998 decreased by $46.8 million to $613.1 million. This decrease was primarily due to lower natural gas supply costs. These costs decreased primarily due to lower natural gas prices, lower sales per customer and warmer weather. These decreased costs were partially offset by customer growth. The amount of natural gas supply costs recorded as an expense is based on the forecast cost of natural gas included in customer rates. Any variances from forecast are deferred until the Alberta Energy and Utilities Board ("AEUB") approves revised rates to either refund or collect the variance. As a consequence, changes in natural gas supply costs have a negligible effect on the Corporation's earnings.

On October 30, 1997, the AEUB approved, among other things, a five year agreement for Northwestern Utilities Limited ("NUL") which changed industrial and producer transportation customer rates and terms and conditions of service effective January 1, 1998. This agreement enhanced NUL's transmission service by reducing transmission costs. A similar agreement for Canadian Western Natural Gas Company Limited ("CWNG") was approved on an interim basis effective February 1, 1999, to December 31, 2002.

On March 31, 1998, the AEUB approved a five year negotiated settlement for NUL which would establish cost of service rates and terms and conditions of service for residential, commercial and institutional customers for 1998 through 2002.

At the request of the AEUB, CWNG conducted negotiations during 1998 to review CWNG's 1997 capital structure and return on common equity and to establish customer rates for 1998. As these negotiations did not result in a settlement, the AEUB is conducting hearings that are scheduled to conclude in March 1999.

On June 16, 1998, NUL and CWNG announced that the operations of the two companies are to be merged and then restructured into two new businesses, one of which will focus on transmitting natural gas throughout Alberta through high pressure pipelines, the other of which will distribute natural gas to industrial, commercial and residential customers, primarily in urban areas. The restructuring is subject to AEUB approval. Hearings to consider this restructuring began in February 1999.

As a result of the restructuring announcement, the negotiated agreement with NUL's residential, commercial and institutional customers was re-opened and a new agreement was reached for the same period as the original agreement through 2002. The AEUB has approved the new agreement effective January 1, 1999.

Regulated Electric Operations

Earnings from regulated electric operations for 1998, which amounted to 45.5% of consolidated earnings of the Corporation, increased by $2.3 million to $86.5 million.

Revenues in 1998 increased by $9.5 million to $672.2 million. This increase was primarily the result of higher sales to the Alberta power pool and higher industrial sales, mainly in the oilfield sector, partially offset by higher refunds to customers resulting primarily from the 1998 negotiated settlement for Alberta Power Limited ("APL").

Operating expenses for 1998 increased by $2.2 million to $297.9 million. The increase was primarily due to higher maintenance costs and higher costs of fuel and purchased power, partially offset by lower general and administrative costs.

Fuel costs in APL are mostly for coal supply. To protect against volatility in coal prices, APL owns or has committed under long term contracts sufficient coal supplies for the anticipated lives of its coal-fired generating plants. These contracts are at prices that are either fixed or indexed to inflation.

On May 19, 1998, the AEUB approved a negotiated settlement for APL establishing customer rates for 1998. On October 30, 1998, APL filed a General Tariff Application with the AEUB for the 1999 and 2000 test years. Hearings for the tariff application are scheduled to be held in the second quarter of 1999.

In March 1997, APL experienced an outage at two 30 MW generating units at its Battle River generating station. These two units have remained out of service since that outage and on January 11, 1999, the AEUB granted APL's application to discontinue operation and dismantle these two units. APL expects dismantling of the units to be completed by December 31, 1999, with no material impact on earnings.

Power Generation

Earnings from power generation operations for 1998, which amounted to 13.7% of consolidated earnings of the Corporation, increased by $5.2 million to $26.1 million.

Revenues in 1998 increased by $18.2 million to $193.0 million. This increase was primarily the result of higher availability at the Barking power station, an increase in the average Sterling exchange rate, and commencement of operations of an 85 MW cogeneration plant at Primrose, Alberta (the "Primrose steam enhancement plant") in October 1998 and a 180 MW cogeneration plant at Osborne, South Australia (the "Osborne cogeneration plant") in December 1998.

Operating expenses for 1998 increased by $10.0 million to $116.4 million. The increase was primarily due to higher availability at the Barking power station together with an increase in the average Sterling exchange rate and higher fuel costs resulting from the commencement of operations of the Primrose steam enhancement plant and the Osborne cogeneration plant.

Fuel costs in power generation operations are for natural gas supply. CU Power International Limited ("CUPIL") obtains its natural gas supplies under long term contracts to protect against volatility in natural gas prices. CUPIL also has the opportunity to purchase natural gas supplies under short term contracts and does so when it is advantageous.

Other Businesses

Earnings from other businesses for 1998, which amounted to 7.5% of consolidated earnings of the Corporation, increased by $2.0 million to $14.2 million.

Revenues in 1998 increased by $27.5 million to $206.3 million. The primary reason for the increase was higher sales of natural gas to third parties, increased natural gas storage, the purchase of ATCO Travel Ltd. in 1998, and new technical services contracts, partially offset by lower natural gas liquids prices and contract changes related to the North Warning System and Voisey's Bay contracts.

Operating expenses for 1998, net of intersegment expenses, increased by $30.0 million. This increase was primarily due to the inclusion of operating costs of ATCO Travel Ltd. beginning in January 1998, and higher natural gas supply costs related to sales to third parties.

LIQUIDITY AND CAPITAL RESOURCES

Cash flow from operations provides a substantial portion of the Corporation's cash requirements. Additional cash requirements are met externally through bank borrowings and the issuance of long term debt, preferred shares and common equity. Commercial paper borrowings and short term bank loans are used to provide flexibility in the timing and amounts of long term financing.

It is the policy of the Corporation to pay dividends quarterly on its Class A non-voting and Class B common shares. In 1998, the Corporation increased the dividends on Class A non-voting and Class B common shares by $0.08 per share, as it did in 1997. The matter of an increase in the quarterly dividend is addressed by the board of directors in the first quarter of each year. For the first quarter of 1999, the quarterly dividend payment has been increased by $0.02 to $0.43 per share. The payment of any dividend is at the discretion of the board of directors and depends on the financial condition of the Corporation and other factors. Since its inception as a holding company in 1972, the Corporation has increased its annual common share dividend for 27 consecutive years.

Cash flow from operations increased by $25.2 million to $426.8 million in 1998, primarily due to higher earnings attributable to Class A non-voting and Class B common shares.

On May 14, 1998, the Corporation filed a notice of intention to make a normal course issuer bid for the purchase of up to 5% of its outstanding Class A non-voting shares during the period May 19, 1998 to May 18, 1999. To date, no shares have been purchased pursuant to this normal course issuer bid.

Investing increased from $317.3 million in 1997 to $375.9 million in 1998, primarily as a result of higher capital expenditures during 1998.

Investment in regulated property, plant and equipment in 1998 remained at 1997 levels of approximately $267 million. Expenditures for property, plant and equipment in non-regulated operations increased from $79.9 million in 1997 to $137.5 million in 1998 as a result of successes in obtaining and commencing construction on new projects in 1998.

To finance 1998 regulated operations, including the redemption of $51.8 million of long term debt having interest rates ranging from 8.37% to 12.00% and $68.1 million of preferred shares having a dividend rate of 5.90%, the Corporation issued $166.5 million of commercial paper and incurred $20.0 million of bank borrowings. It is the Corporation's policy to use commercial paper to provide flexibility in the timing and amounts of long term financing. The $166.5 million of commercial paper and $20.0 million of bank borrowings outstanding at year end are expected to be refinanced with long term financing in 1999.

CU Power Generation Limited entered into a £50.0 million (approximately $128 million) credit agreement with a Canadian chartered bank on January 31, 1997. The Corporation has provided a guarantee of all advances to be made under this agreement. As at December 31, 1998, no funds had been advanced.

CU Power Canada Limited has entered into a $50.0 million long term credit agreement with a Canadian chartered bank on March 19, 1998. This facility is secured by certain assets within the Corporation's power generation group. As at December 31, 1998, $50.0 million had been advanced.

In December 1996, ATCO Gas Services Ltd. entered into a $25.0 million credit agreement with a Canadian chartered bank. The Corporation has provided a guarantee of all advances made and to be made under this agreement. As at December 31, 1998, $25.0 million had been advanced.

In December 1996, the Corporation and a Canadian chartered bank entered into a $60.0 million credit agreement. As at December 31, 1998, $48.2 million had been advanced under this agreement.

In February 1999, CU Power Australia Pty Ltd entered into negotiations to arrange a $50.0 million AUD (approximately $48 million) credit agreement with a Canadian chartered bank. The Corporation will provide a guarantee of all advances made and to be made under this agreement.

The amount and timing of future financings will depend on market conditions and the specific needs of the Corporation.

On April 30, 1998, Dominion Bond Rating Service Limited ("DBRS") reaffirmed the ratings on the Corporation's debt and commercial paper at AA (low), R-1 (middle), respectively, and preferred shares at Pfd-1. Effective October 1, 1998, DBRS broadened its preferred share rating scale and indicated that these changes were definitional changes and were not to be considered as upgrades or downgrades. On October 1, 1998, DBRS altered the Corporation's preferred share rating from Pfd-1 to Pfd-1(low).

On February 15, 1999, Canadian Bond Rating Service Inc. ("CBRS") reaffirmed the ratings on the Corporation's debentures and medium term note debentures at A+ and on commercial paper and preferred shares at A-1+ and P-1, respectively, and changed the rating outlook to negative from stable. CBRS cited the restructuring of the electrical industry in the province of Alberta and the uncertainty related to the proposed change from traditional rate of return regulation to power purchase agreements ("PPAs") as the reason for the change.

Future income tax liabilities of $136.8 million at December 31, 1998, are attributable to differences between the financial statement carrying amounts of assets and liabilities and their tax bases. These differences result primarily from recognizing revenue and expenses in different years for financial and tax reporting purposes. Future income taxes will become payable when such differences are reversed through the settlement of liabilities and realization of assets.

Business Risks

Regulated Operations

The Corporation's regulated operations are subject to the normal risks faced by regulated companies. These risks include the approval by the AEUB of customer rates which permit a reasonable opportunity to recover on a timely basis the estimated costs of providing service, including a fair return on rate base. The Corporation's ability to recover the actual costs of providing service and to earn the approved rates of return depends on achieving the forecasts established in the rate-setting process.

The business risks of APL have changed with the implementation of the Electric Utilities Act in 1996. There is now more forecast risk as each electric utility is exposed to the forecasts of other electric utilities in Alberta as well as the requirement to independently forecast province-wide generation output and pool prices. There is not expected to be a significant impact on earnings given APL's ability to manage these risks.

There will be further changes in the electric utility industry in Alberta. Through legislation passed in 1998, the government of Alberta has set a timetable to pursue a direction, similar to that developing in other jurisdictions, whereby generation is completely deregulated and retail competition is available. This will result in changes to APL's business risk, both at the generation level and in the distribution and retail businesses.

Existing generation is to be deregulated through a system of long term PPAs. PPAs are commercial contracts which will be imposed on generation owners and will be auctioned to a new group of participants known as "marketers". The effect of these contracts will be that the marketers, not generation owners, will be the pool market participants for existing generation. The resulting risk profile of generation owners is uncertain at this time as the exact form of PPA is still being developed under the direction of the Department of Energy of the government of Alberta.

It is anticipated that APL's transmission and distribution activities will continue to be regulated. APL, along with other industry participants, continues to be involved in discussions with the government of Alberta regarding the details of this deregulation process.

The legislation also requires that a regulated "Stable Rate Option" be offered to smaller customers who do not want to exercise their choice of an unregulated retailer. This option is to be available for five years (2001 – 2005).

Non-Regulated Operations

The Corporation's non-regulated operations are outside its traditional regulated businesses, but are related to them in terms of skills, knowledge and experience. The Corporation accounts for its non-regulated operations separately from its regulated operations. The Corporation's non-regulated operations are subject to the risks faced by any commercial enterprise in those industries and in those countries in which the Corporation operates.

By entering into long term contracts with purchasers for the output of projects and with key suppliers, the Corporation is able to limit its risk. In the majority of power generation undertakings to date, risks in respect of fuel and energy prices have by contract been agreed and allocated to the purchasers of the electric energy and the Corporation has not assumed any risks in this regard.

For those projects in Alberta for which there are no long term PPAs, CUPIL purchases its natural gas supplies on the short term market, as it believes that the hourly price of power in the Alberta power pool will, over time, reflect the current market price of natural gas in Alberta.

The Corporation has financed approximately 85% of its non-regulated electrical generating capacity on a non-recourse basis. In these projects, the lender's recourse in the event of default is limited to the business and assets of the project in question and to the Corporation's equity therein. The Corporation's remaining non-regulated projects are financed through long term bank credit facilities and from internally generated cash.

Hedging

It is the policy of the Corporation to use financial instruments to reduce specific risk exposures and not to hold these instruments for trading purposes.

The Corporation has entered into several contracts in order to reduce interest rate, foreign exchange and commodity price risk. The financial impact of these contracts is not material and the counterparty in each transaction is a major financial institution or a significant industry participant.

Corporate Reorganization

On February 11, 1999, the board of directors of Canadian Utilities Limited approved a proposal for a reorganization. The reorganization will see the creation of a new wholly owned subsidiary of Canadian Utilities Limited to be known as CU Inc., which will become the parent company of the Corporation's regulated natural gas and regulated electric subsidiaries. The reorganization is designed to separate the regulated utility operations of the Corporation from its non-regulated operations. Subject to the receipt of all required shareholder and regulatory approvals, the reorganization is expected to be effective June 1, 1999.

Year 2000

The Year 2000 problem results from the practice of using only two digits to represent a year, i.e., 98 is used instead of 1998. When a computer sees 00 as the year, it may not know whether that represents the year 1900 or 2000. Incorrect calculations may result or the program logic may refuse to accept the date and simply stop. This problem is not limited to accounting related applications running on computers. Millions of computer chips that utilize dates have been installed in electronic devices of all types and there is the potential that some of these devices may fail to handle the "00" year correctly. The interconnected nature of computers and electronic devices compounds the problem and increases both the probability and impact of failures.

Like other companies, the Corporation is vulnerable to the failure of its computerized systems and those of its key business partners, such as customers, suppliers, other utilities, government agencies and other third parties. Computers, information technology and electronics are used widely throughout the Corporation to facilitate effective and efficient operations and administration. Most operations systems are industry standard, while many administrative systems have been developed, and are supported, by internal staff.

The Corporation has been working on its Year 2000 Project since 1995. Each subsidiary of the Corporation manages its own Year 2000 project and a Year 2000 Program Manager, who reports directly to the President, has been appointed in each subsidiary. The Corporation has dealt with the Year 2000 issue in a methodical and systematic way, incorporating the following elements into its Year 2000 Project:

Awareness: Informing and educating management and employees about the meaning and scope of the Year 2000 issue;

Identification: Listing all systems and devices potentially affected by the Year 2000 date change;

Assessment: Evaluating the importance of each system and device and determining the need for retirement, replacement or repair. A critical and high priority status is assigned to any system which affects the safe and reliable supply of services and products to the Corporation's customers. The remaining systems, which would impact on efficiency, are evaluated as medium or low priority;

Remediation / Testing: Repairing or replacing impacted systems and devices on a priority basis as necessary. Tests are performed in compliance with established testing guidelines to ensure consistency of results;

Implementation: Integrating the corrected systems and devices into normal production operations;

Clean Management: Monitoring that systems and devices that have been declared Year 2000 ready are protected from changes that may result in the loss of certification as Year 2000 ready;

Audit / Verification: Engaging independent experts to validate progress, results and conclusions;

Participating and co-operating with the information technology industry, natural gas and electric industries, and various regulatory and government agencies for review of preparedness measures and contingency planning;

Evaluating business relationships for Year 2000 responsibility and critically assessing the compliance and readiness efforts of key suppliers and customers;

Business Continuity: Reviewing business processes and completing an impact/risk analysis of Year 2000 issues;

Developing mitigation and contingency plans to deal with potential disruptions in the Corporation's businesses and to address uncertainties regarding key suppliers, business partners and infrastructure.

Activities undertaken across the Corporation include:

- A common definition for the term "Year 2000 Ready" has been established and is being enforced. As well, test guidelines for applications and hardware have been developed and implemented.
- Year 2000 warranty clauses have been included in all new purchase orders and contracts.
- Vendors have been requested to confirm that they will be able to maintain their current level of service after January 1, 2000.
- Key suppliers, customers and business partners have been consulted in an effort to minimize the risk of unexpected problems.
- Reviews of business continuity plans have been conducted and contingency plans have been co-ordinated with industry partners to address possible disruptions caused by unexpected Year 2000 failures from internal and external sources.
- Year 2000 project managers have been appointed for each of the Corporation's subsidiaries, with each project team reporting its progress to senior executives of each company on a monthly basis.

For the Corporation, Year 2000 readiness means that systems or devices have been remediated or replaced and tested as functional, or the ability to work around the system has been established. Year 2000 readiness also includes the preparation of contingency plans to deal with unforeseen impacts.

The Corporation is currently on schedule with its remediation efforts. The Corporation's goal is to have critical and high priority systems substantially ready by April 30, 1999 and the remaining medium / low priority systems ready by July 30, 1999. This schedule will allow time for additional testing and co-ordination of key supplier and industry partners' plans prior to the end of 1999.

The Corporation and its subsidiaries are working towards achieving Year 2000 readiness in accordance with a predetermined schedule. Each company has made significant progress towards Year 2000 readiness with all companies essentially complete in the Awareness, Identification and Assessment stages of their projects. Each company is at a different stage in its project schedule for the Remediation / Testing, and Implementation stages. The Clean Management, Audit / Verification and Business Continuity Planning stages are processes that are repetitive and ongoing and will continue through the Year 2000.

The following table presents the Corporation's expected readiness dates for critical / high priority systems and for medium / low priority systems.

	Critical / High Priority Systems	Medium / Low Priority Systems
Canadian Utilities Limited	April 30, 1999	July 30, 1999
Northwestern Utilities Limited and Canadian Western Natural Gas Company Limited	March 31, 1999	June 30, 1999
Alberta Power Limited	April 30, 1999	June 30, 1999
CU Power International Limited	April 30, 1999	June 30, 1999
ATCO Gas Services Ltd.	March 31, 1999	June 30, 1999
Frontec Corporation	March 31, 1999	June 30, 1999
ATCO Singlepoint Ltd.	April 30, 1999	June 30, 1999
ATCO Energy Ltd.	March 31, 1999	June 30, 1999

The target dates for Year 2000 readiness are based on the information currently available to the Corporation. The existing readiness plans and readiness dates for each company are subject to change.

The Corporation is involved in the supply of both natural gas utility services and electric utility services. A disruption in these services is of particular concern because of the potential impact to customers. The Corporation takes very seriously the issues that arise from the Year 2000 problem and its utility operations have been, and continue to be, committed to the reliable supply of electric and natural gas services.

The objective of the Corporation's Year 2000 Project is to minimize the likelihood of any problems with the reliability of services and to prepare for a prompt and appropriate response should a disruption occur. The utility operations of the Corporation have committed significant resources to the Year 2000 problem and have undertaken a number of precautions including:

- In APL, by April 1999 system clocks will have been set forward at each of its power generating stations and its transmission system to a date in late December 1999. The clocks will then be allowed to advance normally through the key Year 2000 rollover dates and left to operate in the year 2000 until the second quarter of the year 2000. Two of APL's major power generating stations, representing more than one-third of APL's installed capacity, have already been successful in operating through this procedure.
- In CWNG and NUL, integrated testing of systems is being conducted with clocks running through the change to the year 2000 as well as other key date changes.
- Co-operation and sharing of information is established and ongoing with key suppliers, customers, industry associations and various government agencies to minimize the potential of an interruption in service.
- Contingency planning is an established and ongoing effort within the Corporation to address many types of operating disruptions, including acts of nature. The Corporation's utility operations are particularly focused on supplementing existing plans for Year 2000 related interruptions for all critical and high priority systems. These contingency plans include:
- manual control procedures are in place and are being tested
- additional employees will be at key field locations and the remaining staff will be on standby during critical time frames
- additional supplies will be put in place to meet shortfalls that may arise as a result of supplier failure
- procedures are in place to maximize the generating and reserve levels and to minimize the tie line loadings.

This activity is closely tied to the efforts to assess the overall readiness of the Corporation's computerized systems, equipment and business processes and their dependencies on and vulnerabilities to key third party business partners.

Due to the complexity of the Year 2000 issue, including the Corporation's dependence on third parties for important products and services, there can be no assurances that the Year 2000 remediation efforts by the Corporation or of such third parties will be completely successful. The impact of a failure to complete such remediation efforts successfully could have a material adverse effect on the results of operations and financial condition of the Corporation. While there can be no guarantees that disruptions will not occur, based on the approach taken by the Corporation and its understanding of the work done by third parties, the Corporation does not expect widespread or extended interruptions in its businesses or services.

The Corporation has taken the approach of attributing only incremental costs unique to the Year 2000 issue to its program costs. As a result, normal replacement of equipment and software has been excluded from Year 2000 costs even if its replacement is coincidental with the Year 2000 remediation. Consequently, the Corporation's costs for Year 2000 are not considered to be material and are expected to be approximately $12 million. The majority of these costs will extend the service life of the assets and, therefore, it is expected that these costs will be capitalized. The Corporation's Year 2000 cost estimate is based on management's current estimates which are derived from utilizing numerous assumptions of future events and are subject to change.

March 3, 1999

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL REPORTING

Management is responsible for the preparation of the consolidated financial statements, management's discussion and analysis and other financial information relating to the Corporation contained in this annual report. The consolidated financial statements have been prepared in conformity with Canadian generally accepted accounting principles using methods appropriate for the industries in which the Corporation operates and necessarily include some amounts that are based on informed judgments and best estimates of management. The financial information contained elsewhere in the annual report is consistent with that in the consolidated financial statements.

Management depends upon internal accounting control systems to meet its responsibility for reliable and accurate reporting. These control systems are subject to periodic review by the Corporation's internal auditors.

PricewaterhouseCoopers, our independent auditors, are engaged to express a professional opinion on the consolidated financial statements.

The Board of Directors, through its Audit Committee comprised of five non-management directors, oversees management's responsibilities for financial reporting. The Audit Committee meets regularly with management, the internal auditors and the independent auditors to discuss auditing and financial matters, to gain assurance that management is carrying out its responsibilities and to review and approve the consolidated financial statements. The auditors have full and free access to the Audit Committee.

K.M. Watson

J.A. Campbell
Senior Vice President, Finance
and Chief Financial Officer

K.M. Watson
Vice President,
Controller

AUDITORS' REPORT

TO THE SHAREHOLDERS OF CANADIAN UTILITIES LIMITED

We have audited the consolidated balance sheets of Canadian Utilities Limited as at December 31, 1998 and 1997 and the consolidated statements of earnings and retained earnings and changes in cash position for the years then ended. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 1998 and 1997 and the results of its operations and the changes in its cash position for the years then ended in accordance with generally accepted accounting principles.

PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta

February 5, 1999

CONSOLIDATED STATEMENT OF EARNINGS AND RETAINED EARNINGS

(Millions of Canadian Dollars except per share data)

	Note	Year Ended December 31 1998	1997
Revenues		**$1,945.7**	$1,927.6
Costs and expenses			
Natural gas supply		**376.3**	400.8
Fuel and purchased power		**201.6**	193.8
Operation and maintenance		**513.6**	507.0
Depreciation and depletion		**204.1**	196.2
Franchise, property and other taxes		**101.3**	103.9
		1,396.9	1,401.7
Financing charges and other			
Interest expense		**142.1**	138.6
Interest expense on non-recourse long term debt		**30.9**	28.7
Dividends on retractable preferred shares		**18.0**	18.6
Allowance for funds used		**(5.7)**	(6.7)
Interest and other income		**(17.6)**	(15.3)
		167.7	163.9
Earnings before income taxes		**381.1**	362.0
Income taxes	2	**180.5**	168.1
Net earnings		**200.6**	193.9
Dividends on non-retractable equity preferred shares		**10.4**	12.4
Earnings attributable to Class A and Class B shares		**190.2**	181.5
Retained earnings at beginning of year		**737.4**	682.0
		927.6	863.5
Dividends on Class A and Class B shares		**103.9**	99.5
Direct charges	3	**1.1**	26.6
Retained earnings at end of year		**$ 822.6**	$ 737.4
Earnings per Class A and Class B share		**$ 3.00**	$ 2.85
Dividends paid per Class A and Class B share		**$ 1.64**	$ 1.56

CONSOLIDATED BALANCE SHEET

(Millions of Canadian Dollars)

		December 31	
	Note	1998	1997
ASSETS			
Current assets			
Cash and short term investments		$ 66.8	$ 56.2
Accounts receivable		352.1	294.3
Inventories		101.4	87.6
Deferred natural gas costs		6.0	(1.6)
Prepaid expenses		18.4	15.1
		544.7	451.6
Property, plant and equipment	4	3,802.0	3,598.6
Security deposits for debt		28.2	1.1
Deferred financing charges		9.6	12.3
Other assets		52.7	27.1
		$4,437.2	$4,090.7
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current liabilities			
Bank indebtedness		$ 22.0	$ 11.8
Accounts payable and accrued liabilities		255.7	231.9
Accrued interest and dividends		26.7	28.7
Income and other taxes payable		41.4	50.0
Non-recourse long term debt due within one year	5	24.7	16.2
		370.5	338.6
Future income taxes	2	136.8	104.0
Unearned revenues		25.9	18.8
Other deferred credits		17.7	15.8
Notes payable	6	186.5	5.3
Long term debt	5	1,476.2	1,419.3
Non-recourse long term debt	5	422.7	408.5
Retractable preferred shares	7	200.0	325.0
Non-retractable equity preferred shares	7	266.9	210.0
Class A and Class B shareholders' equity			
Class A and Class B shares	8	506.5	505.9
Retained earnings	8	822.6	737.4
Foreign currency translation adjustment		4.9	2.1
		1,334.0	1,245.4
		$4,437.2	$4,090.7

C.O. Twa
Director

B.K. French
Director

CONSOLIDATED STATEMENT OF CHANGES IN CASH POSITION

(Millions of Canadian Dollars)

	Year Ended December 31 1998	1997
Operating		
Earnings attributable to Class A and Class B shares	$190.2	$ 181.5
Non-cash items included in earnings		
Depreciation and depletion	204.1	196.2
Future income taxes	29.0	27.5
Other – net	3.5	(3.6)
Cash flow from operations	426.8	401.6
Change in non-cash working capital	(69.3)	(20.1)
	357.5	381.5
Dividends paid to Class A and Class B shareholders	(103.9)	(99.5)
	253.6	282.0
Investing		
Capital expenditures – net	(410.5)	(353.8)
Contributions by customers for extensions to utility plant	37.8	36.8
Other	(3.2)	(0.3)
	(375.9)	(317.3)
Financing		
Change in notes payable	181.2	1.4
Issue of long term debt	117.4	68.5
Issue of non-recourse long term debt	11.0	59.4
Repayment of long term debt	(60.5)	(56.3)
Repayment of non-recourse long term debt	(17.2)	(15.2)
Security deposits for debt	(25.4)	(1.1)
Redemption of retractable preferred shares	(68.1)	–
Issue of non-retractable equity preferred shares	–	110.0
Redemption of non-retractable equity preferred shares	–	(109.5)
Issue (purchase) of Class A shares	0.6	(24.1)
Other	(16.3)	12.0
	122.7	45.1
Cash position[1]		
Increase	0.4	9.8
Beginning of year	44.4	34.6
End of year	$ 44.8	$ 44.4

[1] Cash position includes cash and short term investments less current bank indebtedness.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Financial Statement Presentation

The consolidated financial statements include the accounts of Canadian Utilities Limited and its subsidiaries, including a proportionate share of joint venture investments ("Canadian Utilities"). The major subsidiaries are Northwestern Utilities Limited and Canadian Western Natural Gas Company Limited (regulated natural gas operations), Alberta Power Limited (regulated electric operations), CU Power International Limited (power generation), ATCO Gas Services Ltd. (natural gas gathering, processing and storage) and Frontec Corporation (technical facilities management). Significant joint venture investments include Thames Power Limited and several cogeneration plants.

Certain comparative figures have been reclassified to conform to the current presentation.

Utility Regulation

The electric and natural gas utility subsidiaries are regulated primarily by the Alberta Energy and Utilities Board ("AEUB"), which administers acts and regulations covering such matters as rates, financing, accounting, construction, operation and service area. The AEUB may award interim rates, subject to final determination.

Revenue Recognition

Revenues are recognized on the accrual basis and include an estimate of services provided but not yet billed.

Revenues resulting from the supply of contracted services are recorded by the percentage of completion method. Full provision is made for any anticipated loss.

The Electric Utilities Act ("EUA") provides for the sale of all power for use in Alberta to a power pool for resale to distribution companies at a bid price that matches demand with supply. Existing generating units can recover a return on investment and costs of production from the distribution companies. Over-recoveries can arise where pool prices exceed variable production costs and are repayable to the distribution companies. These cost recovery mechanisms apply to existing regulated generating units. New units that are brought into production receive only pool prices.

Under provisions of the EUA, The Transmission Administrator pays the regulated costs of the electric subsidiary's transmission facilities. The Transmission Administrator administers transmission services needed to serve customers throughout Alberta and charges a uniform tariff to all distribution companies.

Natural Gas Supply

Natural gas supply expense is based on the forecast cost of natural gas included in customer rates. Variances from forecast costs are deferred until such time as approval from the AEUB is obtained for refund to or collection from customers through revised rates and natural gas supply expense is adjusted accordingly.

Income Taxes

Each regulated electric and natural gas utility follows the method of accounting for income taxes that is consistent with the method of determining the income tax component of its rates. When future income taxes are not provided in the income tax component of current rates, such future income taxes are not recognized to the extent that it is expected that they will be recovered from customers through inclusion in future rates.

Other subsidiaries follow the liability method of accounting for income taxes. Under this method future tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases. Future tax liabilities and assets are measured using enacted tax rates. The effect on future tax liabilities and assets of a change in tax rates is recognized in income in the period that the change occurs.

Property, Plant and Equipment

The utility subsidiaries include in capital expenditures an allowance for funds used during construction at rates approved by the AEUB for debt and equity capital. Capital expenditures in the other subsidiaries include capitalized interest incurred during construction.

Certain utility additions are made with the assistance of non-refundable cash contributions from customers when the estimated revenue is less than the cost of providing service or where special equipment is needed to supply the customers' specific requirements. These contributions are amortized on the same basis as, and offset the depreciation charge of, the assets to which they relate. Property, plant and equipment is disclosed net of unamortized contributions.

Depreciation is provided on assets on a straight-line basis over their estimated useful lives. Depreciation rates for utility assets are approved by the AEUB. For certain utility assets these approved depreciation rates include a provision for future removal costs and site restoration costs. On retirement of depreciable utility assets, the accumulated depreciation is charged with the cost of the retired unit, net disposal costs and site restoration costs.

Deferred Financing Charges

Expenses of the issue of long term debt are amortized over the weighted average life of the debt and expenses of the issue of preferred shares are amortized over the expected life of the issue. Unamortized premiums and issue costs of redeemed long term debt and preferred shares are amortized over the life of the issue funding the redemption.

Notes Payable

Under bank loan agreements that are renewed on a continuing basis, Canadian Utilities may issue commercial paper or borrow directly from the bank. These borrowings allow Canadian Utilities to manage the amount and timing of long term debt, preferred share and equity issues and are classified as long term.

Long Term Debt Due Within One Year

When Canadian Utilities intends to refinance long term debt due within one year on a long term basis and there is a written undertaking from an underwriter to act on Canadian Utilities' behalf with respect thereto, or sufficient capacity under long term bank loan agreements to issue commercial paper or assume bank loans, then long term debt due within one year is classified as long term.

Hedging

In conducting its business, Canadian Utilities uses various instruments, including forward contracts, swaps and options, to manage the risks arising from fluctuations in exchange rates, interest rates and commodity prices. All such instruments are used only to manage risk and not for trading purposes.

Gains and losses are recognized in income in the same period and in the same financial statement category as the income or expense from the hedged position.

Retirement Benefits

Canadian Utilities has defined benefit pension plans covering approximately 75% of its employees. Employees participate through contributions to the plans, which provide for pensions based on length of service and final average earnings. The cost of pension benefits is determined using the projected benefits method prorated on service and reflects management's best estimates of investment returns, wage and salary increases, and age at retirement. Plan assets are valued based on a three year average of market values. Adjustments resulting from plan enhancements, experience gains and losses and changes in assumptions are amortized over the estimated average remaining service life of employees.

Canadian Utilities also has defined contribution pension plans for employees. Employer contributions are expensed as incurred.

The cost of other benefits, principally health, dental and life insurance for retirees and their dependents, is expensed as paid.

2. INCOME TAXES

The income tax provision differs from that computed using the statutory tax rates for the following reasons:

	1998		1997	
Earnings before income taxes	$ 381.1	%	$ 362.0	%
Income taxes, at statutory rates	$ 169.8	44.6	$ 161.5	44.6
Dividends on retractable preferred shares	8.0	2.1	8.3	2.3
Allowance for funds used	(1.4)	(0.4)	(1.5)	(0.4)
Depreciation of capitalized allowance for funds used	3.7	1.0	3.6	1.0
Crown royalties and other non-deductible Crown payments	3.1	0.8	3.0	0.8
Earned depletion and resource allowance	(4.5)	(1.2)	(4.5)	(1.2)
Unrecorded future income taxes	1.2	0.3	(3.2)	(0.9)
Large Corporations Tax	5.5	1.4	4.3	1.2
Foreign tax rate variance	(4.9)	(1.3)	(3.8)	(1.1)
Change in future income taxes resulting from reduction in United Kingdom tax rate	(1.3)	(0.3)	(1.8)	(0.5)
Non-deductible interest on foreign financing	1.8	0.5	2.0	0.6
Other	(0.5)	(0.1)	0.2	–
	180.5	47.4	168.1	46.4
Current income taxes	147.7		140.3	
Future income taxes	$ 32.8		$ 27.8	

The future income tax liabilities comprise the following:

	1998	1997
Property, plant and equipment	$ 144.1	$ 127.3
Allowance for funds used	8.2	5.6
Deferred pension costs	1.9	2.2
Reserves	1.6	(7.8)
Tax loss carryforwards	(18.1)	(21.0)
Other	3.2	(2.0)
	140.9	104.3
Less: Amounts included in income and other taxes payable	4.1	0.3
	$ 136.8	$ 104.0

Unrecorded future income taxes of the utility subsidiaries decreased by $1.2 million to $178.6 million at December 31, 1998.

Expected future recoveries relating to tax loss carryforwards have been recorded in the amount of $18.1 million, of which $1.3 million expires in 2005 and $16.8 million does not expire.

3. DIRECT CHARGES TO RETAINED EARNINGS

	1998	1997
Purchase of Class A shares	$ –	$ 18.8
Adjustment to opening retained earnings for prior years' effect of change in method of accounting for income taxes	–	6.6
Stock options settled (after income taxes)	1.1	1.2
	$ 1.1	$ 26.6

4. PROPERTY, PLANT AND EQUIPMENT

		1998		1997	
	Composite Depreciation Rates	Cost	Accumulated Depreciation	Cost	Accumulated Depreciation
Regulated natural gas operations	3.9%	$ 2,208.0	$ 748.3	$ 2,094.1	$ 696.6
Regulated electric operations	3.6%	3,163.1	1,137.4	3,061.2	1,053.9
Power generation	3.4%	657.2	65.1	502.1	44.8
Other	5.8%	143.8	29.0	126.0	21.9
		$ 6,172.1	1,979.8	$ 5,783.4	1,817.2
Property, plant and equipment, less accumulated depreciation			4,192.3		3,966.2
Unamortized contributions by customers for extensions to utility plant			390.3		367.6
			$ 3,802.0		$ 3,598.6

Accumulated depreciation includes an amount provided for future removal and site restoration costs, net of salvage value, of $156.9 million (1997 – $137.1 million).

Composite depreciation rates reflect total depreciation expensed and capitalized as a percentage of mid-year cost, excluding non-depreciable assets and construction work-in-progress.

5. LONG TERM DEBT

	1998	1997
Debentures		
1988 Series 11.25% due September 1998	$ –	$ 50.0
1995 Medium Term Note 7.55% due January 1999	42.0	42.0
1994 Medium Term Note 8.81% due April 2000	50.0	50.0
1997 Medium Term Note 5.42% due November 2002	68.0	68.0
1993 Series 7.25% due September 2003	60.0	60.0
1994 Series 8.73% due June 2004	100.0	100.0
1995 Series 8.43% due June 2005	125.0	125.0
1986 Series 9.85% due October 2006, redeemable October 2001	100.0	100.0
1986 Second Series 10.25% due December 2006, redeemable December 2001	90.0	90.0
1987 Series 12% due October 2007, redeemable October 2002	125.0	125.0
1989 Series 10.20% due November 2009	125.0	125.0
1990 Series 11.40% due August 2010	125.0	125.0
1990 Second Series 11.77% due November 2020	100.0	100.0
1991 Series 9.92% due April 2022	125.0	125.0
1992 Series 9.40% due May 2023	100.0	100.0
	1,335.0	1,385.0
Canadian Utilities Limited credit facility, at Bankers' Acceptance rates, due December 2003	48.2	–
CU Power Canada Limited credit facility, at Bankers' Acceptance rates, due March 2003	50.0	–
Other long term obligations, at rates from 5.32% to 11.125%	43.0	34.3
	$ 1,476.2	$ 1,419.3
Non-recourse (secured only by specific project assets)		
Barking Power Limited project financing, due to 2010, payable in British pounds:		
At fixed rates averaging 7.95%	$ 124.0	$ 116.6
At London Interbank Offered Rate plus 0.5095%	205.4	196.3
Osborne Cogeneration Pty Ltd. project financing, at 10.795%, due to 2013, payable in Australian dollars	67.1	55.1
McMahon cogeneration plant term facility, at 9.135%, due to 2004	21.4	25.2
Industrial Gas System credit facility, at 7.32%, due to 2006	29.5	31.5
	447.4	424.7
Less: Amounts due within one year	24.7	16.2
	$ 422.7	$ 408.5

The interest rates disclosed for certain of the non-recourse debt obligations reflect the effect of interest rate swap agreements.

The minimum annual debt repayments for each of the next five years are as follows:

	Long Term Debt	Non-Recourse Long Term Debt	Total
1999	$ 42.9	$ 24.7	$ 67.6
2000	63.7	28.3	92.0
2001	0.2	30.6	30.8
2002	71.2	32.4	103.6
2003	183.2	35.0	218.2
	$ 361.2	$ 151.0	$ 512.2

Of the $67.6 million due in 1999, $42.9 million is to be refinanced and is, therefore, excluded from long term debt due within one year in the balance sheet.

Redemption Privileges

Certain debentures of Canadian Utilities are redeemable prior to maturity on the dates specified above at the principal value plus accrued and unpaid interest.

Fair Values

Fair values for the above debt, determined using quoted market prices for the same or similar issues, are shown below. Where market prices are not available, fair values are estimated using discounted cash flow analysis based on Canadian Utilities' current borrowing rate for similar borrowing arrangements.

	1998	1997
Long term debt – fixed rate	$ 1,734.7	$ 1,762.2
– floating rate	127.0	18.5
	$ 1,861.7	$ 1,780.7
Non-recourse long term debt – fixed rate	$ 276.8	$ 250.6
– floating rate	205.4	196.3
	$ 482.2	$ 446.9

Interest Expense

Interest expense is shown net of interest capitalized of $2.0 million (1997 – nil) and interest expense on non-recourse long term debt is shown net of interest capitalized of $5.9 million (1997 – $2.7 million).

6. NOTES PAYABLE AND CREDIT LINES

At December 31, 1998, Canadian Utilities notes payable includes outstanding commercial paper of $166.5 million (1997 - $5.3 million), at interest rates ranging from 5.175% to 5.225%, maturing March 1999, and bank borrowings of $20.0 million (1997 – nil) at an interest rate of 5.24%, maturing January 1999.

Canadian Utilities has credit lines totaling $668.8 million, of which $422.2 million are available on a committed basis by the lenders and $246.6 million are available on an uncommitted basis. These credit lines enable Canadian Utilities to obtain financing for general business purposes. At December 31, 1998, $299.0 million of committed credit lines and $204.6 million of uncommitted credit lines were still available.

7. PREFERRED SHARES

Authorized: An unlimited number of Series Second Preferred Shares, issuable in series.

Issued:

	Stated Value	Retraction and Redemption Dates	1998 Shares	1998 Amount	1997 Shares	1997 Amount
	(dollars)					
Retractable						
Cumulative Redeemable Second Preferred Shares						
5.9% Series Q	$25.00	–	–	$ –	5,000,000	$ 125.0
5.3% Series R	$25.00	June 1, 1999	6,000,000	150.0	6,000,000	150.0
6.6% Series S	$25.00	March 1, 2000	2,000,000	50.0	2,000,000	50.0
				$ 200.0		$ 325.0
Non-retractable						
Cumulative Redeemable Second Preferred Shares						
5.9% Series Q	$25.00	open	2,277,675	$ 56.9	–	$ –
Perpetual Cumulative Second Preferred Shares						
5.4% Series O	$25.00	May 1, 1999	1,600,000	40.0	1,600,000	40.0
4.63% Series T	$25.00	December 2, 2001	1,600,000	40.0	1,600,000	40.0
4.63% Series U	$25.00	November 26, 2001	800,000	20.0	800,000	20.0
4.66% Series V	$25.00	October 3, 2002	4,400,000	110.0	4,400,000	110.0
				$ 266.9		$ 210.0

On December 1, 1998, 2,722,325 of Cumulative Redeemable Second Preferred Shares Series Q were retracted at a price of $25.00 per share plus accrued dividends.

The dividends payable on the Perpetual Cumulative Second Preferred Shares Series O, T, U and V are fixed until May 1, 1999, December 2, 2001, November 26, 2001 and October 3, 2002, respectively, at which time a new dividend rate may be established by negotiation between Canadian Utilities Limited and the holders of the shares.

Fair Values

Fair values for preferred shares determined using quoted market prices for the same or similar issues are:

	1998	1997
Retractable	$ 202.2	$ 330.7
Non-retractable	$ 269.8	$ 211.2

Redemption and Retraction Privileges

The retractable Cumulative Redeemable Second Preferred Shares are retractable on the dates specified above at the option of the holder at the stated value plus accrued and unpaid dividends. The retractable and non-retractable preferred shares are redeemable on the dates specified above at the stated value plus accrued and unpaid dividends.

8. CLASS A AND CLASS B SHARES

	Class A Non-Voting		Class B Common		Total	
	Shares	Consideration	Shares	Consideration	Shares	Consideration
Authorized:	Unlimited		Unlimited			
Issued and Outstanding:						
December 31, 1996	39,844,548	$ 358.4	24,125,957	$ 152.8	63,970,505	$ 511.2
Purchased	(659,220)	(6.0)	–	–	(659,220)	(6.0)
Stock options exercised	28,400	0.7	–	–	28,400	0.7
Converted: Class B to Class A	31,284	0.2	(31,284)	(0.2)	–	–
December 31, 1997	39,245,012	353.3	24,094,673	152.6	63,339,685	505.9
Stock options exercised	22,600	0.6	–	–	22,600	0.6
Converted: Class B to Class A	94,605	0.6	(94,605)	(0.6)	–	–
December 31, 1998	**39,362,217**	**$ 354.5**	**24,000,068**	**$ 152.0**	**63,362,285**	**$ 506.5**

Shareholder Rights

The holders of the Class A non-voting shares and the Class B common shares are entitled to share equally, on a share for share basis, in all dividends declared by Canadian Utilities Limited on either of such classes of shares as well as the remaining property of Canadian Utilities Limited upon dissolution. The holders of the Class B common shares are entitled to vote and to exchange at any time each share held for one Class A non-voting share.

If a take-over bid is made for the Class B common shares which would result in the offeror owning more than 50% of the outstanding Class B common shares and which would constitute a change in control of Canadian Utilities Limited, holders of Class A non-voting shares are entitled, for the duration of the bid, to exchange their Class A non-voting shares for Class B common shares and to tender such Class B common shares pursuant to the terms of the take-over bid. Such right of exchange is conditional upon the completion of the take-over bid giving rise to the right of exchange, and if the take-over bid is not

completed, then the right of exchange shall be deemed never to have existed. In addition, holders of the Class A non-voting shares are entitled to exchange their shares for Class B common shares of Canadian Utilities Limited if ATCO Ltd., the present controlling shareholder of Canadian Utilities Limited, ceases to own or control, directly or indirectly, more than 10,000,000 of the issued and outstanding Class B common shares of Canadian Utilities Limited. In either case, each Class A non-voting share is exchangeable for one Class B common share, subject to changes in the exchange ratio for certain events such as a stock split or rights offering. The complete text of the rights of exchange attached to the Class A non-voting shares is set out in a Certificate of Amendment dated September 10, 1982 issued to Canadian Utilities Limited.

Normal Course Issuer Bid

On May 19, 1998, Canadian Utilities Limited commenced a Normal Course Issuer Bid for the purchase of up to 5% of the outstanding Class A non-voting shares. The offer will expire on May 18, 1999.

Stock Option Plan

Canadian Utilities Limited has a stock option plan under which directors, officers and key employees may purchase Class A non-voting shares at $23.76 to $46.21 on or before dates extending from February 1, 2005 to July 8, 2008. The exercise of the outstanding options would not materially dilute earnings per Class A and Class B share. Changes in shares under option are summarized below:

	1998	1997
Options at beginning of year	819,100	742,000
Granted	142,500	258,000
Exercised	(22,600)	(28,400)
Settled	(93,150)	(152,500)
Options at end of year	845,850	819,100

Retained Earnings

The debenture trust indenture places certain limitations on Canadian Utilities which include restrictions on the payment of dividends on Class A non-voting and Class B common shares. Consolidated retained earnings in the amount of $226.2 million are free from such restrictions.

9. JOINT VENTURES

Canadian Utilities' interest in joint ventures is summarized below:

	1998	1997
Statement of earnings		
Revenues	$ 206.3	$ 188.8
Operating expenses	123.5	115.7
Depreciation	16.9	15.5
Financing charges and other	23.7	22.1
Earnings from joint ventures before income taxes	$ 42.2	$ 35.5
Balance sheet		
Current assets	$ 125.1	$ 95.9
Current liabilities	(71.5)	(69.2)
Property, plant and equipment	554.1	456.6
Deferred items – net	(63.3)	(50.4)
Long term debt	(16.0)	–
Non-recourse long term debt (secured only by joint venture assets)	(396.0)	(378.7)
Investment in joint ventures	$ 132.4	$ 54.2
Statement of changes in cash position		
Operating	$ 50.6	$ 45.7
Investing	(82.1)	(66.3)
Financing	38.2	21.8
Increase in cash position	$ 6.7	$ 1.2

Current assets include cash of $41.0 million (1997 – $35.1 million) which is only available for use within the joint ventures.

10. RELATED PARTY TRANSACTIONS

In the normal course of business with its parent corporation, ATCO Ltd., and affiliated companies, Canadian Utilities incurred administrative expenses and licensing fees totaling $0.8 million (1997 – $2.0 million) and recovered administrative expenses and business development costs totaling $2.0 million (1997 – $1.9 million).

11. RETIREMENT BENEFITS

The present values of the accrued pension benefits based on actuarial calculations and the net assets available to provide for pensions under the defined benefit plan are as follows:

	1998	1997
Market value of assets	$ 1,093.4	$ 1,058.0
Accrued pension benefits	817.8	748.6
Surplus	$ 275.6	$ 309.4

12. COMMITMENTS AND CONTINGENCIES

Minimum operating lease payments, which extend over periods not exceeding 13 years, are as follows:

1999	2000	2001	2002	2003	Total of All Subesequent Years
$12.1	$11.4	$11.0	$10.6	$8.9	$24.1

Canadian Utilities is party to a number of disputes and lawsuits in the normal course of business. Management is confident that the ultimate liability arising from these matters will have no material impact on the consolidated financial statements.

On August 17, 1998, Canadian Western Natural Gas Company Limited filed an application with the AEUB for 1997 return on common equity and capital structure, and a general rate application for 1998. The hearing is being conducted during the first quarter of 1999, and a decision is expected by the end of 1999. The decision is not expected to have a material effect on the consolidated financial statements.

13. SEGMENTED INFORMATION

Canadian Utilities operates in three primary business segments:

Regulated natural gas operations provide natural gas production, transmission and distribution to industrial, residential and commercial customers in Alberta;

Regulated electric operations provide electric power generation, transmission and distribution to industrial, commercial and residential customers in north central Alberta and parts of the Yukon and the Northwest Territories;

Power generation owns and operates non-regulated electric generating facilities in Canada, Great Britain and Australia.

Other businesses consist of: natural gas gathering, processing, storage and natural gas supply management; technical facilities management for the defence, transportation and industrial sectors; and customer billing and call centre services for gas and electric utilities, marketers and municipalities.

Business Segments

1998 / 1997	Regulated Natural Gas Operations	Regulated Electric Operations	Power Generation	Other Businesses	Corporate	Intersegment Eliminations	Consolidated
Revenues – external	$ 873.5	$ 672.2	$ 193.0	$ 206.3	$ 0.7	$ –	$ 1,945.7
	$ 910.8	$ 662.7	$ 174.8	$ 178.8	$ 0.5	$ –	$ 1,927.6
Revenues – intersegment[1]	8.6	3.9	–	70.9	9.5	(92.9)	–
	5.4	2.4	–	10.8	11.8	(30.4)	–
Revenues	882.1	676.1	193.0	277.2	10.2	(92.9)	1,945.7
	916.2	665.1	174.8	189.6	12.3	(30.4)	1,927.6
Operating expenses	613.1	297.9	116.4	242.3	14.7	(91.6)	1,192.8
	659.9	295.7	106.4	158.3	15.3	(30.1)	1,205.5
Depreciation and depletion	74.2	105.1	16.9	7.9	0.3	(0.3)	204.1
	73.5	100.9	15.7	6.0	0.4	(0.3)	196.2
Interest expense on debt	53.3	87.9	29.9	4.9	135.7	(138.7)	173.0
	48.2	89.4	28.2	5.0	135.8	(139.3)	167.3
Dividends on retractable preferred shares	6.3	11.7	–	–	–	–	18.0
	6.5	12.1	–	–	–	–	18.6
Allowance for funds used	(1.9)	(3.8)	–	–	–	–	(5.7)
	(1.4)	(5.3)	–	–	–	–	(6.7)
Interest and other income	(2.3)	(1.6)	(10.6)	(2.5)	(139.3)	138.7	(17.6)
	(3.0)	(1.4)	(7.9)	(1.8)	(140.5)	139.3	(15.3)
Earnings before income taxes	139.4	178.9	40.4	24.6	(1.2)	(1.0)	381.1
	132.5	173.7	32.4	22.1	1.3	–	362.0
Income taxes	68.0	88.7	14.3	10.4	(0.5)	(0.4)	180.5
	61.8	84.5	11.5	9.9	0.4	–	168.1
Net earnings	71.4	90.2	26.1	14.2	(0.7)	(0.6)	200.6
	70.7	89.2	20.9	12.2	0.9	–	193.9
Dividends on non-retractable equity preferred shares	2.7	3.7	–	–	4.0	–	10.4
	3.4	5.0	–	–	4.0	–	12.4
Earnings attributable to Class A and Class B shares	$ 68.7	$ 86.5	$ 26.1	$ 14.2	$ (4.7)	$ (0.6)	$ 190.2
	$ 67.3	$ 84.2	$ 20.9	$ 12.2	$ (3.1)	$ –	$ 181.5
Total assets	$1,478.8	$ 2,059.7	$ 721.5	$ 205.0	$ 12.8	$ (40.6)	$ 4,437.2
	$ 1,365.6	$ 2,026.8	$ 564.6	$ 163.7	$ 19.9	$ (49.9)	$ 4,090.7
Capital expenditures	$ 143.5	$ 124.4	$ 119.3	$ 18.1	$ 0.1	$ –	$ 405.4
	$ 144.6	$ 122.4	$ 66.5	$ 10.6	$ 2.8	$ –	$ 346.9

[1] Intersegment revenues are recognized on the basis of prevailing market or regulated prices.

Geographic Segments

	Domestic		Foreign		Consolidated	
	1998	1997	**1998**	1997	**1998**	1997
Revenues	**$ 1,767.3**	$1,765.9	**$ 178.4**	$161.7	**$ 1,945.7**	$1,927.6
Capital assets	**$ 3,355.0**	$3,192.3	**$ 447.0**	$406.3	**$ 3,802.0**	$3,598.6

14. UNCERTAINTY DUE TO THE YEAR 2000 ISSUE

The Year 2000 Issue arises because many computerized systems use two digits rather than four to identify a year. Date-sensitive systems may recognize the year 2000 as 1900 or some other date, resulting in errors when information using year 2000 dates is processed. In addition, similar problems may arise in some systems which use certain dates in 1999 to represent something other than a date. The effects of the Year 2000 Issue may be experienced before, on, or after January 1, 2000, and, if not addressed, the impact on operations and financial reporting may affect an entity's ability to conduct normal business operations. While Canadian Utilities has implemented a Year 2000 program, it is not possible to be certain that all aspects of the Year 2000 Issue affecting Canadian Utilities, including those related to the efforts of customers, suppliers, or other third parties, will be fully resolved.

CANADIAN UTILITIES LIMITED
CONSOLIDATED FIVE-YEAR FINANCIAL SUMMARY

(Dollars in millions, except as indicated)		**1998**	1997	1996	1995	1994
EARNINGS						
Revenues		**1,945.7**	1,927.6	1,813.1	1,674.0	1,662.5
Costs and expenses	Natural gas supply	**376.3**	400.8	311.1	275.8	409.9
	Fuel and purchased power	**201.6**	193.8	175.6	164.1	126.7
	Operation and maintenance	**513.6**	507.0	498.6	465.5	393.5
	Depreciation and depletion	**204.1**	196.2	188.2	172.6	160.2
	Franchise, property and other taxes	**101.3**	103.9	98.6	93.5	98.8
		1,396.9	1,401.7	1,272.1	1,171.5	1,189.1
Financing charges and other	Interest expense	**142.1**	138.6	150.4	153.3	150.2
	Interest expense on non-recourse long term debt	**30.9**	28.7	30.8	22.4	0.2
	Dividends on retractable preferred shares	**18.0**	18.6	27.8	31.6	32.3
	Allowance for funds used	**(5.7)**	(6.7)	(6.6)	(6.6)	(4.0)
	Interest and other income	**(17.6)**	(15.3)	(14.6)	(9.4)	(5.0)
		167.7	163.9	187.8	191.3	173.7
Earnings before income taxes		**381.1**	362.0	353.2	311.2	299.7
Income taxes		**180.5**	168.1	172.8	149.5	148.8
Net earnings		**200.6**	193.9	180.4	161.7	150.9
Dividends on non-retractable equity preferred shares		**10.4**	12.4	9.1	10.5	12.7
Earnings attributable to Class A and Class B shares		**190.2**	181.5	171.3	151.2	138.2
SEGMENTED EARNINGS						
Regulated natural gas operations		**68.7**	67.3	72.8	59.8	55.1
Regulated electric operations		**86.5**	84.2	72.0	79.2	77.9
Power generation		**26.1**	20.9	16.7	12.0	5.4
Other businesses		**14.2**	12.2	14.8	9.2	9.8
Corporate/Eliminations		**(5.3)**	(3.1)	(5.0)	(9.0)	(10.0)
		190.2	181.5	171.3	151.2	138.2
CASH FLOWS						
Operations		**426.8**	401.6	383.0	340.8	294.8
Class A and B dividends		**103.9**	99.5	94.5	92.4	89.5
Capital expenditures - net		**410.5**	353.8	257.6	329.0	309.6
Financing		**122.7**	45.1	(202.2)	165.1	100.7
CLASS A & B SHARES						
Shares outstanding* (thousands)	At end of year	**63,362**	63,340	63,971	63,707	62,132
	Average for year	**63,359**	63,714	63,940	63,695	62,132
Return on equity* (earnings attributable / weighted average equity)		**14.8%**	14.8%	14.8%	14.0%	13.7%
Earnings per share* ($) (earnings attributable / weighted average shares)		**3.00**	2.85	2.68	2.37	2.22
Dividends paid per share* ($)		**1.64**	1.56	1.48	1.46	1.44
Equity per share* ($) (shareholders' equity / end of year shares)		**21.05**	19.66	18.70	17.42	16.62
Stock market record - Class A non-voting shares	High	**48.85**	41.25	34.50	26.25	27.00
	Low	**38.00**	30.40	25.13	21.88	21.88
	Close	**48.00**	40.65	30.55	26.00	24.00
	Daily trading volume	**19,928**	23,874	28,701	25,106	18,748
Stock market record - Class B common shares	High	**49.00**	41.20	34.50	26.25	27.38
	Low	**38.25**	30.65	25.50	22.00	23.13
	Close	**48.40**	40.70	30.10	26.00	24.13
	Daily trading volume	**3,262**	6,967	1,441	8,311	3,589
OTHER FINANCIAL INDICATORS						
Payout ratio (dividends / earnings attributable)		**55%**	55%	55%	61%	65%
Interest coverage (pretax)		**3.31**	3.27	3.10	2.95	3.21
BALANCE SHEET						
Property, plant, and equipment - gross		**6,172.1**	5,783.4	5,460.8	5,200.6	4,928.7
- net of contributions		**3,802.0**	3,598.6	3,474.4	3,397.8	3,274.3
Total assets		**4,437.2**	4,090.7	3,936.6	3,906.2	3,680.3
Capitalization						
Notes payable and long term debt		**1,662.7**	1,424.6	1,410.9	1,553.9	1,423.5
Non-recourse long term debt		**422.7**	408.5	370.3	345.9	282.6
Retractable preferred shares		**200.0**	325.0	325.0	450.0	550.0
Non-retractable equity preferred shares		**266.9**	210.0	209.5	156.4	139.0
Shareholders' equity*		**1,334.0**	1,245.4	1,195.9	1,109.8	1,033.0
Total capitalization		**3,886.3**	3,613.5	3,511.6	3,616.0	3,428.1
Capitalization ratios - year-end						
Notes payable and long term debt		**43%**	39%	40%	43%	42%
Non-recourse long term debt		**11%**	11%	11%	9%	8%
Retractable preferred shares		**5%**	9%	9%	13%	16%
Non-retractable equity preferred shares		**7%**	6%	6%	4%	4%
Shareholders' equity*		**34%**	35%	34%	31%	30%

* *Includes Class A non-voting shares and Class B common shares.*

CANADIAN UTILITIES LIMITED
CONSOLIDATED FIVE-YEAR OPERATING SUMMARY

(Dollars in millions, except as indicated)	**1998**	1997	1996	1995	1994
Regulated Natural Gas Operations					
Capital expenditures - net	**144.4**	147.5	83.6	131.0	119.3
Pipelines (thousands of kilometres)	**40.5**	39.8	38.8	38.4	37.6
Maximum daily demand (terajoules)	**3,033**	2,791	2,821	2,650	2,335
Sales (petajoules)	**211**	212	242	217	211
Transportation (petajoules)	**611**	508	464	337	302
Sales and transportation - affiliates (petajoules)	**32**	21	21	100	65
Total system throughput (petajoules)	**854**	741	727	654	578
Average annual use per residential customer (gigajoules)	**144**	148	175	157	154
Average annual billing per residential customer ($)	**607**	677	648	602	695
Degree days – Edmonton *	**3,898**	3,964	5,018	4,322	4,274
– Calgary **	**4,160**	4,197	5,190	4,465	4,225
Customers at year-end (thousands)	**779.9**	756.6	738.1	725.2	713.8
Regulated Electric Operations					
Capital expenditures - net	**128.9**	127.0	129.7	121.3	102.1
Generating capacity (thousands of kilowatts)	**1,387**	1,452	1,446	1,446	1,439
Maximum hourly demand (thousands of kilowatts)	**1,434**	1,324	1,331	1,454	1,313
Power lines (thousands of kilometres)	**55.3**	54.9	53.9	53.1	51.3
Retail sales (millions of kilowatt hours)	**10,188**	10,089	9,760	8,886	8,595
Average annual use per residential customer (kWh)	**7,274**	7,381	7,743	7,479	7,573
Customers at year-end (thousands)	**186.4**	183.3	179.8	176.8	174.0
Power Generation					
Capital expenditures - net	**119.3**	66.3	13.7	41.9	86.5
Generating capacity (thousands of kilowatts)	**482**	322	322	322	60
Sales (millions of kilowatt hours)	**2,470**	2,348	2,322	1,609	412

** Degree days – Edmonton - are defined as the difference of the mean daily temperature from 14.5 degrees Celsius.*
*** Degree days – Calgary - are defined as the difference of the mean daily temperature from 15.5 degrees Celsius.*

Corporate Information

CANADIAN UTILITIES LIMITED
OPERATING COMPANIES AND DIVISIONS

Electric Power

ATCO Electric Ltd.

- Ashcor Technologies Ltd.
- Energen Inc.
- Northland Utilities (NWT) Limited
- Northland Utilities (Yellowknife) Limited
- The Yukon Electrical Company Limited

ATCO Power Ltd.

- ATCO Power Canada Ltd.
- Barking Power Limited
- CU Power Australia Pty Ltd.
- CU Power Generation Ltd.
- Thames Power Limited
- Thames Power Services Limited
- Thames Valley Power Limited

Natural Gas

ATCO Gas

ATCO Midstream Ltd.

ATCO Pipelines

CU Water Limited

Technical Services & Facilities Management

ATCO Frontec Corp.

- ATCO Frontec Logistics Corp.
- ATCO Frontec Property Management
- ATCO Frontec Security Services
- ATCO Frontec Services Inc.
- ATCO Frontec Services Ltd.
- ATCO Travel Ltd.
- Narwhal Arctic Services
- Tli Cho Logistics
- Torngait Services Inc.
- Uqsuq Corporation

Energy Marketing & Services

ATCO Energy Ltd.

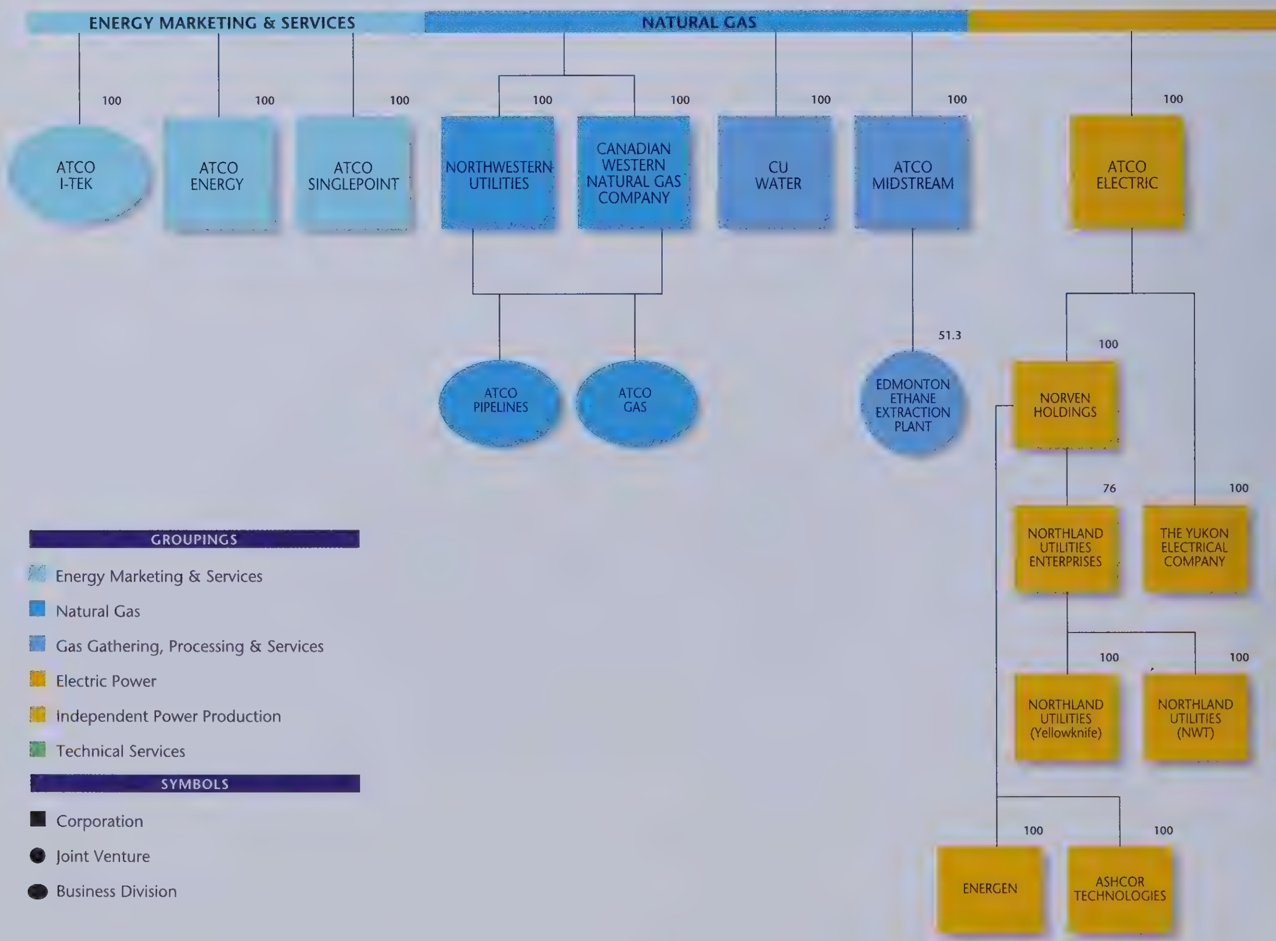
ATCO Singlepoint Ltd.

ATCO I-Tek

CORPORATE HEAD OFFICE
1500, 909 – 11th Avenue S.W.
Calgary, Alberta T2R 1N6
Telephone: (403) 292-7500
Fax: (403) 292-7643
Website: www.atco.ca

Corporate Structure

(Percentage of voting shares held by the parent company)

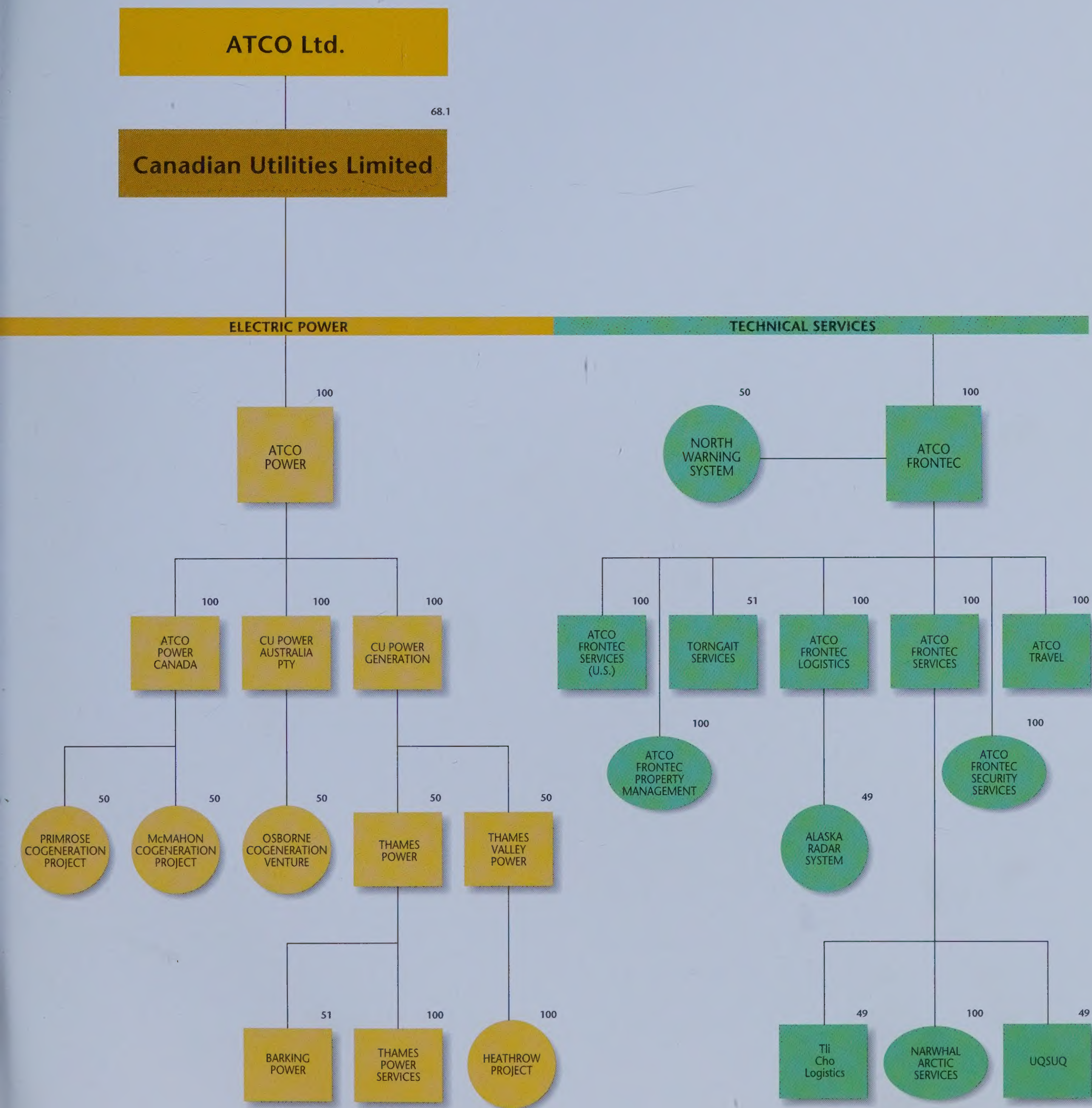


GROUPINGS

- Energy Marketing & Services
- Natural Gas
- Gas Gathering, Processing & Services
- Electric Power
- Independent Power Production
- Technical Services

SYMBOLS

- Corporation
- Joint Venture
- Business Division


ATCO Ltd.
68.1
Canadian Utilities Limited
ELECTRIC POWER
TECHNICAL SERVICES
100
ATCO POWER
50
NORTH WARNING SYSTEM
100
ATCO FRONTEC
100
ATCO POWER CANADA
100
CU POWER AUSTRALIA PTY
100
CU POWER GENERATION
100
ATCO FRONTEC SERVICES (U.S.)
51
TORNGAIT SERVICES
100
ATCO FRONTEC LOGISTICS
100
ATCO FRONTEC SERVICES
100
ATCO TRAVEL
100
ATCO FRONTEC PROPERTY MANAGEMENT
100
ATCO FRONTEC SECURITY SERVICES
50
PRIMROSE COGENERATION PROJECT
50
McMAHON COGENERATION PROJECT
50
OSBORNE COGENERATION VENTURE
50
THAMES POWER
50
THAMES VALLEY POWER
49
ALASKA RADAR SYSTEM
51
BARKING POWER
100
THAMES POWER SERVICES
100
HEATHROW PROJECT
49
Tli Cho Logistics
100
NARWHAL ARCTIC SERVICES
49
UQSUQ

Directors and Officers

BOARD OF DIRECTORS

Robert T. Booth (2) (3)
Partner
Bennett Jones
Calgary, Alberta

W.L. Britton, Q.C. (1)
Partner
Bennett Jones
Calgary, Alberta

B.P. Drummond
Corporate Director
Montreal, Quebec

B.K. French (2) (3)
President
Karusel Management Ltd.
Calgary, Alberta

V.L. Horte
President
V.L. Horte Ventures Inc.
Calgary, Alberta

W.R. Horton (2) (3)
Corporate Director
Winfield, B.C.

H.E. Joudrie (1)
Chairman of the Board
Gulf Canada Resources Limited
Toronto, Ontario

R.W.A. Laidlaw (1)
Corporate Director
Calgary, Alberta

Rt. Hon. D.F. Mazankowski, P.C., D.Eng., LL.D. (1)(4)
Business Consultant and
Corporate Director
Vegreville, Alberta

H.M. Neldner (2) (3) (4)
Corporate Director
Edmonton, Alberta

L.R. Shaben
Chairman
Western New Ventures
Capital Corporation
Edmonton, Alberta

N.C. Southern
Deputy Chairman of the Board
and Deputy Chief Executive Officer
Canadian Utilities Limited
Calgary, Alberta

R.D. Southern, C.B.E., C.M., LL.D.
Chairman of the Board and
Chief Executive Officer
Canadian Utilities Limited
Calgary, Alberta

D.L. Tait, F.R.I., F.C.A. (2) (3) (4)
President
Tait Management Services Ltd.
Lethbridge, Alberta

C.O. Twa
President and Chief
Operating Officer
Canadian Utilities Limited
Calgary, Alberta

(1) Member of the Corporate Governance – Nomination, Succession and Compensation Committee
(2) Member of the Audit Committee
(3) Member of the Risk Review Committee
(4) Member of the Pension Fund Committee

OFFICERS

R.D. Southern
Chairman of the Board and
Chief Executive Officer

N.C. Southern
Deputy Chairman of the Board
and Deputy Chief Executive Officer

C.O. Twa
President and Chief
Operating Officer

J.A. Campbell
Senior Vice President, Finance
and Chief Financial Officer

D.R. Cawsey
Assistant Corporate Secretary
and Manager, Human Resources

D.T. Davis
Vice President, Internal Audit

P.J. House
Vice President, Corporate Secretary

S.W. Kiefer
Vice President, Information
Technology and Chief
Information Officer

C.S. McConnell
Treasurer

L.J. Vegh
Vice President, Insurance

K.M. Watson
Vice President, Controller

S.R. Werth
Vice President, Administration

PRESIDENTS OF PRINCIPAL OPERATING SUBSIDIARIES AND DIVISIONS

C.R. Armour
Managing Director
Australia/Asia Pacific

G.K. Bauer
President
ATCO Power Ltd.

D.M. Ellard
President
ATCO Singlepoint Ltd.

J.R. Frey
President
ATCO Electric Ltd.

J.D. Graham
President
ATCO Pipelines

G.N. Paicu
President and
Chief Executive Officer
ATCO Frontec Corp.

M.M. Shaw
President
ATCO Midstream Ltd.

C.K. Sheard
President
ATCO Gas

G.W. Welsh
President
ATCO Energy Ltd.

Shareholders' Information

INCORPORATION

Canadian Utilities Limited was incorporated under the laws of Canada on May 18, 1927 and was continued under the Canada Business Corporations Act by Articles of Continuance on August 15, 1979.

ANNUAL MEETING

The annual meeting of shareholders will be held at 10:00 a.m., Wednesday, May 12, 1999 at Hotel Macdonald, Edmonton, Alberta.

AUDITORS

PricewaterhouseCoopers
Calgary, Alberta

COUNSEL

Bennett Jones
Calgary, Alberta

TRANSFER AGENT AND REGISTRAR

Class A non-voting and
Class B common shares
and Second Preferred
(Series Q, R and S) Shares
CIBC Mellon Trust Company
Montreal/Toronto/Calgary/Vancouver

TRUSTEE AND REGISTRAR

Debentures
National Trust Company
by its agent
CIBC Mellon Trust Company
Montreal/Toronto/Winnipeg/
Calgary/Vancouver

STOCK EXCHANGE LISTINGS

	Symbol	Listing
Class A non-voting	CU	Toronto
Class B common	CU.X	Montreal
		Alberta

CUMULATIVE REDEEMABLE SECOND PREFERRED SHARES

5.90% Series Q	CU.PR.T	Toronto
5.30% Series R	CU.PR.V	Montreal
6.60% Series S	CU.PR.D	

ATCO GROUP ANNUAL REPORTS

Annual Reports to Shareholders and Management's Discussion and Analysis for Canadian Utilities Limited and its parent company, ATCO Ltd., are available upon request from:

ATCO Ltd. & Canadian Utilities Limited
1500, 909 - 11th Avenue S.W.
Calgary, Alberta T2R 1N6
Telephone: (403) 292-7500
Website: www.atco.ca

SHAREHOLDER INQUIRIES

Dividend information and other inquiries concerning shares should be directed to:

CIBC Mellon Trust Company
Stock Transfer Department
600 The Dome Tower
333 - 7th Avenue, S.W.
Calgary, Alberta T2P 2Z1
Telephone 1-800-387-0825
e-mail: inquiries@cibcmellon.ca

CANADIAN UTILITIES LIMITED

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